| | | |
|---|---|---|
| **Gorham Energy, Limited Partnership** | **)** | **Department** |
| **Cumberland County** | **)** | **Findings of Fact and Order** |
| **Gorham, Maine** | **)** | **Air Emission License** |
| **A-735-71-A-N** | **)** | |

After review of the air emission license application, staff investigation reports, and other documents in the applicant's file in the Bureau of Air Quality, pursuant to 38 M.R.S.A., Section 344 and Section 590, the Department finds the following facts:

## I. REGISTRATION

### A. Introduction

Gorham Energy, Limited Partnership (Gorham Energy) submitted an application for a new major source on April 21, 1998, to be located in Gorham, Maine.

Gorham Energy will be a nominally-rated 900 megawatt (MW) electric generation plant utilizing three ABB GT-24 combustion turbines, with heat recovery steam generators (HRSGs) configured in a combined cycle. The hot exhaust gas from the combustion turbine is used in the heat recovery steam generator to produce superheated steam which drives a steam turbine to generate additional electricity. The primary fuel will be natural gas with low sulfur distillate oil as backup. The cycle cooling will occur through an air cooled condenser system (dry).

### B. Emission Equipment to be Licensed

**Fuel Burning Equipment**

| Equipment* | Licensed Capacity ** MMBtu/hr | Fuel Type, %Sulfur | Nominal Design Firing Rate | Stack # | Control Device |
|---|---|---|---|---|---|
| Turbine System #1 | 2002 *** | Natural Gas | scf/hr | 1 | SCR, CO catalyst |
| | | #2 Fuel Oil, 0.05% | gal/hr | | |

| Equipment* | Licensed Capacity ** MMBtu/hr | Fuel Type, %Sulfur | Nominal Design Firing Rate | Stack # | Control Device |
|---|---|---|---|---|---|
| Turbine System #2 | 2002 *** | Natural Gas | scf/hr | 2 | SCR, CO catalyst |
| | | #2 Fuel Oil, 0.05% | gal/hr | | |
| Turbine System #3 | 2002 *** | Natural Gas | scf/hr | 3 | SCR, CO catalyst |
| | | #2 Fuel Oil, 0.05% | gal/hr | | |
| Fire Pump | 2.2 | Diesel | gal/hr | 4 | None |
| Emergency generators 3 | 3.3 (each) | Diesel | gal/hr | 5,6,7 | None |

Notes: * The turbine system includes the combustion turbine and the heat recovery steam generator (the HRSG is not duct fired).

** The design capacity is based on rated capacity at 0°F, 55% relative humidity burning natural gas.

Maximum total heat input for all three units will be 6582 MMBtu/hr (higher heating value at 0°F ambient) during natural gas firing with steam injection and 6690 MMBtu/hr (higher heating value at 0°F ambient) when firing distillate oil.

*** High heating value

C. Application Classification

A new source is considered major based on whether or not its maximum licensed allowed emissions exceed the "Significant Emission Levels" as given in Maine's Air Regulations. The future maximum licensed allowed emissions are as follows:

| Pollutant | Future License (TPY) | Sig.Level (TPY) |
|---|---|---|
| PM | 328 | 100 |
| $PM_{10}$ | 328 | 100 |
| $SO_2$ | 98 | 100 |
| $NO_x$ | 248.63 | 100 |
| CO | 283 | 100 |
| VOC | 49.8 | 50 |

The new source is major for all criteria pollutants except VOC. All criteria pollutant emissions associated with this new source are subject to Prevention of Significant Deterioration (PSD) review. A Best Available Control Technology (BACT) finding is required for PM, $SO_2$, CO, and VOC.

D. Offsets

Gorham Energy is to be located in Cumberland County which is one of the three counties in southern Maine designated nonattainment for ozone. Both VOC and $NO_X$ are considered precursors to ozone. The proposed $NO_X$ emissions are above the significant emission level, therefore Gorham Energy is required to meet Lowest Achievable Emission Rates (LAER) and obtain $NO_X$ offsets.

The offset ratio required for offsets obtained from sources in New England is 1.15 ton to 1 ton. Gorham Energy has identified 286 tons/year of $NO_X$ emission reduction credits to offset the proposed $NO_X$ annual emissions of 248.63 tons/year. Gorham Energy has proposed to use a combination of 184.7 tons/year of emission reduction credits from Nantucket Electric Co. and 101.3 tons/year of emissions reduction credits from Ogden Energy Group, Inc., both located in Massachusetts. The associated facilities have been permanently shutdown. For the Nantucket emission reduction credits obtained, Gorham Energy has submitted a bill of sale, a transfer letter from the owner to the Massachusetts DEP and a letter from the Massachusetts DEP approving the credits. For the Ogden emission reduction credits, Gorham Energy has submitted an Agreement for Purchase and Sale of Emission Offset Credits with Odgen Energy Group, Inc. to obtain $NO_x$ offsets from Ogden's federally enforceable shutdown of its waste-burning facility in Lawrence, Massachusetts. Ogden is in the process of obtaining Massachusetts DEP certification for these and Gorham Energy has provided a copy of Ogden's application for certification, submitted to the Massachusetts DEP on July 15, 1998. By virtue of the permanent shutdown of these facilities and the supporting documentation mentioned above, these $NO_x$ emission reduction credits satisfy the offset requirements of Chapter 113.

## II. BEST PRACTICAL TREATMENT

A. Introduction

In order to receive a license the applicant must control emissions from each unit to a level considered by the Department to represent best practical treatment (BPT), as defined in Chapter 100 of the Department regulations. Separate control requirement categories exist for new and existing equipment as well as for those sources located in designated non-attainment areas. Descriptions of the applicable requirements are provided below under the appropriate headings.

*System Description*

The Gorham Energy facility is a combined cycle electric generation facility, which consists of the following major mechanical plant components:

- Three ABB GT-24 power trains, each comprised of a combustion turbine, steam turbine, and electric generator. The combustion turbine units are designed to operate on natural gas or fuel oil.

- Three Heat Recovery Steam Generators (HRSGs) utilizing the hot exhaust gases from the combustion turbines.
- A diesel fire pump.
- Three emergency electrical generating engines (referred to as emergency generators).

Each of the three generation systems will consist of a combustion turbine and the HRSG. Combustion air enters through the inlet air filters and is compressed by the turbine-driven compressor. Fuel and compressed air are mixed and burned in the combustion section of the turbine, creating a high-pressure, hot gas. This gas is then expanded through the power turbine section where most of its thermal energy is converted to work as it turns the turbine, producing electricity. The combustion turbine drives both the air compressor and the electric generator.

Energy from the turbine exhaust is recovered in the HRSG by passing the exhaust gas over water and steam filled tubes to make high pressure steam. The high pressure steam is routed to the steam turbine which is connected to the combustion turbine generator through a self-synchronizing clutch, whereby increasing the power output of the generator. Within the HRSG, the exhaust gas passes through an oxidation catalyst and then through an SCR unit before exiting the stack.

The systems are also capable of steam injection for power augmentation for peak power demands. The power augmentation process is when steam generated in the HRSG is injected into the combustion turbine to provide additional electricity for each power train. This additional electricity is approximately 20 MW per power train.

The three power train systems each work most efficiently between 75% to 100% of their rated capacity. The units will normally fire natural gas, with distillate oil available for back-up. At different temperatures and loads, the power inputs and outputs vary. Gorham Energy has proposed a license restriction limiting the operation of any power train to 75% of its design load or greater, except for startup or shutdown.

B. Generation Systems #1, #2, #3

BPT for new sources and modifications requires a demonstration that emissions are receiving Best Available Control Technology (BACT) as defined in Chapter 100 of the Air Regulations. BACT is a top down approach to selecting air emission controls considering economic, environmental and energy impacts. The Gorham Energy facility is also subject to Lowest Achievable Emission Rate (LAER) requirements for $NO_X$, as defined in Chapter 100 of the Bureau of Air Quality regulations.

Generation systems #1, #2, and #3 will each produce approximately 300 MW of electricity, using both the combustion gas turbine generators and HRSGs. Each combustion turbine is rated at approximately 180 MW output capacity (210 MW with steam injection). Each

HRSG generates steam which turns a steam turbine with a nominal 95 MW capacity (85 MW with steam injection). Emissions from each generation system shall be vented through separate stacks (1, 2, and 3) which will be 165 feet tall and represents 60% of Good Engineering Practice (GEP) formula height.

1. **Best Available Control Technology (BACT)**

Gorham Energy has proposed BACT for the generation systems to be the following:

| | | | | |
|---|---|---|---|---|
| $PM/PM_{10}$ | - | combustion of clean fuels (natural gas, 0.05% sulfur #2 oil) | | |
| | | natural gas 27 lb/hr | oil | 112 lb/hr |
| $SO_2$ | - | combustion of clean fuels | | |
| | | natural gas sulfur content of 0.8 grains/100scf | | |
| | | oil sulfur content no greater than 0.05% (#2 fuel) | | |
| CO | - | dry-sequential system combustor* (with CO catalyst) | | |
| | | natural gas 5 ppm | oil | 10 ppm |
| VOC (as $CH_4$) | | dry-sequential system combustor* | | |
| | | natural gas 0.0017 lb/MMBtu | oil | 0.0085 lb/MMBtu |
| | | steam injection 0.005 lb/MMBtu | | |
| Ammonia | | 20 ppmdv, 24-hour average: 10 ppmdv, 30-day average | | |
| Opacity | | shall not exceed 20% opacity, measured as 6 minute averages, except for one 6 minute average period per hour of not more than 27% opacity. | | |

Continuous Emission Monitors for $NH_3$, CO, $O_2$

* The dry sequential system provides integration of a staged, premixed combustor, with computer controlled air and fuel feed systems, and performance monitoring sensors.

A summary of the BACT analysis for each of the pollutants is discussed below.

a. *PM and $PM_{10}$*

Gorham Energy has proposed the combustion of clean fuels and good combustion practices as BACT for particulate matter emissions from the generation systems. Particulate add-on controls have not been applied on gas or oil-fired turbine facilities.

Chapter 103 of the Department regulations (Fuel Burning Equipment Particulate Emission Standard) is applicable to Gorham Energy, however the BACT particulate emission limit of 27 lb/hr for natural gas and 112 lb/hr for oil (based on 0.01 lb/MMBtu and 0.05 lb/MMBtu, respectively) is more stringent. Compliance with the BACT limit is compliance with Chapter 103.

b. *$SO_2$*

Gorham Energy identified flue gas desulfurization systems and the combustion of clean fuels as potential control technologies for $SO_2$ emissions. At this time there have been no flue gas desulfurization systems applied to natural gas or oil-fired combustion turbine facilities. Thus, Gorham Energy has proposed the combustion of clean fuels as BACT for sulfur dioxide emissions from the generation systems.

Chapter 106 of the Department's regulation (Low Sulfur Fuel) is applicable to Gorham Energy. The BACT limit of 0.05% sulfur #2 fuel is below the fuel sulfur content in Chapter 106.

c. *CO*
Gorham Energy identified and has proposed the utilization of an oxidation catalyst and good combustion practices as BACT for carbon monoxide emissions from the combustion turbines and HRSGs. Gorham Energy shall install and operate CO and $O_2$ continuous emission monitoring systems.

d. *VOC*
Gorham Energy identified combustion control and an oxidation catalyst as potential control technologies for VOC. VOC emissions are a function of incomplete combustion. At low load operation (50%), the catalyst can be effective at completing combustion as well as reducing CO emissions. However, Gorham Energy proposes to restrict its operational range to 75% load and greater. Gorham Energy has proposed good combustion practices as BACT for volatile organic compound emissions from the generation systems.

e. *Ammonia*
Gorham Energy shall have a 10 ppm limit on ammonia on a 30 day average and 20 ppm on a 24-hour average from each system. Ammonia emissions result from unreacted ammonia which has been injected into the HRSG system as part of the SCR system. In order to guarantee the low 2.5 ppmdv level of $NO_X$ emissions when firing natural gas, excess ammonia must be injected into the HRSG. This excess is referred to as ammonia slip. The BACT/LAER Clearinghouse has shown ammonia slip limits ranging from 10 ppm to 20 ppm. One $NO_X$ control catalyst technology that does not use ammonia is the $SCONO_X$™ technology. However, $SCONO_X$™ has not been demonstrated on full commercial operation for a large facility (see LAER discussion below).

BACT for ammonia is the proposed SCR for $NO_X$ with design, maintenance and replacement schedules consistent with achieving ammonia slip rates of less than 20 ppmdv on a 24 hour average, and 10 ppmdv on a 30 day average. Gorham Energy shall install and operate a $NH_3$ continuous emission monitor on each generation unit.

f. *Opacity*
Chapter 101 of the Department's regulations (Visible Emissions) is applicable to Gorham Energy, however, the BACT opacity limit in this license is more stringent. Visible emissions from each of the generation system shall not exceed 20% opacity, measured as

6 minute averages, except for one 6 minute average period per hour of not more than 27% opacity.

2. **Lowest Achievable Emission Rate (LAER)**

Gorham Energy has proposed LAER for $NO_X$ emissions from the generation systems to be the following:

| | | |
|---|---|---|
| Combustion Turbine $NO_x$ | - | Low $NO_x$ combustors |
| Generation System $NO_x$ | - | Selective Catalytic Reduction (SCR) |
| | | 7 ppm ammonia |

2.5 ppmvd limit for $NO_X$ during gas firing
3.5 ppmvd limit for $NO_X$ during steam injection
9.0 ppmvd limit for $NO_X$ during oil firing
$NO_X$ Continuous Emission Monitor

$NO_X$ emissions from combustion sources results from the oxidation of both fuel bound nitrogen and atmospheric nitrogen (thermal $NO_X$). Natural gas has very low fuel bound nitrogen so reducing $NO_X$ emissions focuses on reducing the thermal $NO_X$. Distillate fuel oil has fuel bound nitrogen which contributes to the overall $NO_X$ emission rate.

*Gas Firing*
The RACT/BACT/LAER Clearinghouse was used to identify the most stringent control requirement for similar gas fired projects. The lowest emission limit achieved in practice was found to be 3.5 ppm using SCR.

SCR uses an ammonia injection system and a catalytic reactor to reduce $NO_x$. An injection grid disperses ammonia ($NH_3$) into the flue gas upstream of the catalyst and the $NH_3$ and $NO_X$ are reduced to nitrogen gas ($N_2$) and water vapor ($H_2O$) in the presence of the catalyst reactor.

In addition, Gorham Energy researched the Goal Line Environmental Technologies $SCONO_X$™ catalytic absorption system. This system does not require the use of ammonia. The $SCONO_X$™ process oxidizes both CO and NO to $CO_2$ and $NO_2$ with subsequent absorption of $NO_2$ by a proprietary catalytic absorber. The technology has been used on a 34 MW combined cycle system with daily averages under 3.5 ppmv.

Gorham Energy assessed the technical and commercial availability of $SCONO_X$™ in the following areas:

- Potential Difficulties with Scale-up
  The Gorham Energy project is on a much larger scale - almost six times the gas flow. This could cause design and performance guarantee problems since nothing on the larger scale has been designed and tested at this time.

- System Reliability/Efficiency
  The system reliability was shown to be high, however, this reliability was demonstrated only over three months rather than several years. The process also involves a larger backpressure in the HRSG. This backpressure is more than the conventional SCR system and is expected to adversely affect the power output guarantees.
- Project Schedule
  The Gorham Energy facility is projected to be on line by the summer of 2000 to meet the peak electricity demand of the region. The proposed project is configured to be able to meet power output, energy efficiency and environmental standards without extensive specific modifications. Replacing the proposed SCR with a $SCONO_X$™ system would require additional time for testing and redesign.
- Incompatibility with backup oil firing
  The efficiency of the $SCONO_X$™ system is adversely affected by even the trace amounts of sulfur present in the flue gases from gas burning. Thus, problems are likely to be experienced when firing oil, even though oil firing has not been tested. The technology manufacturers have developed a sulfur removal system to be used on conjunction with the $NO_X$ system, however, there is no full scale operating history with the system referred to as $SCOSO_X$™.

LAER for Gorham Energy shall be $NO_X$ emissions of 2.5 ppmdv on a 3-hour block average basis when firing natural gas. During steam injection, the $NO_X$ limit shall be 3.5 ppmdv on a 3-hour block average basis. Although a facility in New York has a license with a shorter averaging time, the source has exceeded its 3.5 ppm $NO_X$ limit for about 1-2% of the source operating time for two quarters in 1997. LAER is defined as the more stringent rate of emissions based on the following:

- The most stringent emission limitation which is contained in the implementation plan of any State for that class or category of source, unless the owner or operator of the proposed source demonstrates that those <u>limitations are not achievable</u>; or
- The most stringent emission limitation which is <u>achieved in practice</u> by that class or category of source, whichever is more stringent. In no event may LAER result in emission of any pollutant in excess of those standards and limitations promulgated pursuant to Section 111 or 112 of the United States Clean Air Act as amended, or any emission standard established by the Department.

Based on the New York facility, the 3.5 ppm on a one hour basis has not been 'achieved in practice' without a number of exceedances. The 3 hour averaging period will allow Gorham Energy to better account for, react to and compensate for routine operational swings, and therefore enable Gorham Energy to minimize exceedances.

*Oil Firing*
The RACT/BACT/LAER Clearinghouse showed that 9 ppm is the lowest permitted $NO_X$ emission limit for these size units. One facility was licensed less than 9 ppm , but that air permit has been withdrawn and the project is not going to be constructed.

3. **New Source Performance Standards (NSPS)**

The three turbines are subject to New Source Performance Standards (NSPS), 40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines, for which construction is commenced after October 3, 1977.

40 CFR Part 60, Subpart GG establishes the following emission limits:
Pursuant to 40 CFR Part 60.333 $SO_2$ is limited to (a) 0.015% by volume @ 15% $O_2$ on a dry basis or (b) the fuel sulfur content shall not exceed 0.8% by weight.

Pursuant to 40 CFR Part 60.332(a)(1) NOx is limited based on the following equation:

$$NO_x \quad STD = 0.0075 * (14.4/Y) + F,$$

where STD is the allowable NOx emissions (ppm by volume at 15% $O_2$ and on a dry basis), Y is a function of the manufacturer's rated load (kilojoules per watt hour), and F is a function of the fuel-bound nitrogen. NSPS establishes a NOx emission limit of 75 ppmdv at 100% load and ISO conditions. By meeting the more stringent LAER emission limit, Gorham Energy will be in compliance with the NSPS limit.

Additionally, NSPS requires Gorham Energy to monitor the fuel-bound nitrogen and sulfur content of the fuel for every bulk storage shipment, daily if there is no immediate bulk storage, or on an Administrator approved schedule.

NSPS also requires Gorham Energy to continuously monitor and record the fuel consumption and the ratio of water to fuel being fired, if a water injection system is utilized for NOx emission control during oil firing.

B. Emergency Diesel Fire Pump

The emergency diesel fire pump shall meet BACT through the firing of 0.05% sulfur oil and having a limit of 500 hours/year based on a 12 month rolling total. Emissions from the diesel fire pump were obtained using the EPA AP-42 emission factors (Table 3.3-1 dated 10/96) and assuming all sulfur in the fuel oil converts to $SO_2$.

C. Emergency Generators

The three emergency generators shall meet BACT through the firing of 0.05% sulfur oil and having a limit of 500 hours/year (for each generator) based on a 12 month rolling total. Emissions from the emergency generators were based on vendor supplied data and assuming all sulfur in the fuel oil converts to $SO_2$. The emergency generators shall be operated only when one or more of the combustion turbines is shut down, or is in the process of being shut down.

D. Annual Emission Restrictions

Gorham Energy shall be restricted to the following annual emissions, based on a 12 month rolling total:

**Total Allowable Annual Emissions for the Facility**
(used to calculate the annual license fee)

| Pollutant | tons/year |
|---|---|
| PM | 328 |
| $PM_{10}$ | 328 |
| $SO_2$ | 98 |
| $NO_X$ | 248.63 |
| CO | 283 |
| VOC | 49.8 |
| Ammonia | 346 |

The allowable oil firing in the generation systems shall be based on the maximum VOC emissions, calculated by the following equation:

$$(1/2000) \text{ x } (0.0017\ Q_{gas} + 0.0085\ Q_{oil} + 0.005Q_{SI}) < 49 \text{ tons/year}$$

where: 1/2000 is the conversion factor from lb to tons
$Q_{gas}$ = total heat input (MMBtu) from gas firing (excluding steam injection)
$Q_{oil}$ = total heat input (MMBtu) from oil firing
$Q_{SI}$ = total heat input (MMBtu) from gas firing with steam injection

The equation is based on the VOC emissions rates in lb/MMBtu since the lb/MMBtu rates do not change over the proposed operating range and for changes in ambient temperature. The total hours of oil firing may be divided in any portion between the three generation units.

Gorham Energy may request that the lb/MMBtu VOC emission limits in the formula be revised to lower limits based on stack test results.

C. Additional Facility Requirements

1. **Title V Operating Permit Program**

As a major source, Gorham Energy will be subject to the Federal Title V Operating Permit Program. The application for Gorham Energy has been processed under Chapter 115 of the Department's regulations. Within 12 months of initial startup, Gorham Energy shall submit a complete application for an initial Part 70 license pursuant to Chapter 140 of the Department's regulations.

2. **Sections 112(g) & Section 112(r) - Clean Air Act Amendments of 1990**

Section 112(g) of the CAAA of 1990 requires a MACT (Maximum Achievable Control Technology) analysis for a new major source of hazardous air pollutants. However, 40 CFR Part 63.40(a) exempts electric utility steam generating units from the MACT and related air toxic provisions.

Section 112(r) - Accidental Release Prevention Program - applies to listed toxic chemicals above a threshold quantity. Aqueous ammonia with a concentration of 20% or greater is listed at a threshold quantity of 10,000 lbs. Gorham Energy plans to store aqueous ammonia for the SCR system in excess of 10,000 lbs, however the concentration will be less than 20% solution and therefore no 112(r) plan is required.

3. **Acid Rain**

Title IV of the CAAA of 1990 is a program to control $SO_2$ and $NO_X$ emissions that contribute to the formation of acid precipitation. Gorham Energy will be classified as a Phase II 'new affected unit', effective January 1, 2000, or within 90 days after commencement of commercial operations, whichever is later.

Per Title IV requirements, Gorham Energy shall:

- acquire and hold $SO_2$ allowances in the amount of one allowance for each ton of $SO_2$ emitted. Allowances are commodities traded on the Chicago Board of Trade;
- install continuous emissions monitoring systems (CEMS) that meet the specification of 40 CFR Part 75;
- name a designated representative to be responsible for submitting compliance monitoring reports and for obtaining necessary allowances on behalf of the facility; and
- submit an acid rain license application to DEP.

## III. AMBIENT AIR QUALITY ANALYSIS

A. Overview

A combination of screening and refined modeling was performed to show that the proposed Gorham Energy Limited Partnership (GELP) facility emissions, in conjunction with other sources, would not cause or contribute to violations of Maine Ambient Air Quality Standards (MAAQS) for $SO_2$, $PM_{10}$, $NO_2$, and CO, or to Class I or Class II increments for $SO_2$, $PM_{10}$ and $NO_2$. In addition, analyses were performed to show that GELP's emissions will not adversely impact other Class I and II air quality related values (AQRV's).

B. Model Inputs

The SCREEN3 (Version 96043) and COMPLEX I (VALLEY Mode) (Version 92290) (CIVM) models were used to address standards and increment in intermediate and complex terrain (terrain with elevations above the stack top elevation). The ISCST3 model (Version 97363) using sequential meteorological data and a network of receptors was used to address standards in simple and intermediate terrain (terrain with elevations below the final plume rise elevation). The CALPUFF modeling system consisting of CALMET (Version 5.0 Level 980304), CALPUFF (Version 5.0 Level 980615) and CALPOST (Version 5.0 Level 980515) was used to address standards in the nearest Class I area. CALMET is a diagnostic meteorological model, CALPUFF is a non-steady state puff model and CALPOST processes concentration data produced by CALPUFF.

All SCREEN3, CIVM and ISCST3 modeling was performed in accordance with all applicable requirements of the Maine Department of Environmental Protection, Bureau of Air Quality (MEDEP-BAQ) and the United States Environmental Protection Agency (USEPA). The CALPUFF modeling system was performed in accordance with the September 11, 1998 recommendations of the CALPUFF Workgroup of the May 1998 Orlando, Florida EPA/STATE/LOCAL Modeling Workshop. The Workgroup recommends: “if at least one, long range transport, source-receptor relationship is expected to be important to the calculation of the ‘design concentrations’ that CALPUFF be listed as a refined Appendix A model.” Given this recommendation, no equivalency demonstration is required to use CALPUFF for long range transport calculations.

A valid 5-year hourly meteorological off-site database was used in the ISCST3 refined modeling. The primary wind data was collected at a height of 10 meters at the Portland National Weather Service (PNWS) site located at the Portland International Jetport during the 5-year period 1986-1990. All five years of meteorological data contained no missing data. Hourly cloud cover, ceiling height and surface wind speed data, also from the PNWS were used to calculate stability. Hourly mixing heights were derived from PNWS surface and upper air data.

The CALPUFF Workgroup recommends that a minimum of one year of meteorological data should be required if the three dimensional time and space varying wind fields are derived from high quality data such as prognostic four-dimensional data-assimilated data. In accordance with this recommendation, the "initial guess" wind field used in the CALMET processor was the Mesoscale Model Version 4 (MM4) 1990 database prepared by EPA. Other meteorological data used to derive the final wind fields in the CALMET processor as listed in Table IV-1 were 11 surface, 1 buoy, 3 upper air, 2 ozone monitoring and 16 precipitation stations. Table IV-2 summarizes all options used in the CALMET analysis.

The horizontal dimensions of the CALPUFF modeling system domain is 140km x 130km in east-west and north-south directions, respectively. The southwest corner of the domain is located at UTM coordinates 277.0 km Easting, 4808.0 km Northing. The horizontal resolution of the domain is 1 km with 10 vertical layers (0-20m, 20-40m, 40-80m, 80-160m, 160-300m, 300-600m, 600-1000m, 1000-1500m, 1500-2200m and 2200-3000m).

United States Geological Survey (USGS) land use data from the Composite Theme Grid format (CTG) data set with a resolution of 200m was used to determine the fractional land use category information for each 1-km grid cell. For each grid cell the albedo, Bowen ratio, roughness length and leaf area index were computed as a weighted average based on the fractional land use information.

The USGS 3 arc-second (~90 m) digital elevation models (DEMs) were used to derive gridded terrain elevations. All USGS elevation records located within each grid cell of the domain were averaged to produce a mean elevation at the grid point.

**Table IV-1. CALMET Meteorological and Geophysical Data Sources**

| DATA | Vertical Layer | Domain Grid Coverage (UTM coordinates in km) | Source |
|---|---|---|---|
| **PROGNOSTIC four-dimensional data-assimilated data** | | | |
| MM4 | All | Entire Grid | EPA |
| **Geophysical Data** | | | |
| Composite Theme Grid format (CTG) USGS land use data | Surface | Entire grid | USGS |
| 1-degree USGS DEM's | Surface | Entire grid | USGS |
| **Hourly Land Surface Stations** | | | |
| Bangor, ME | Surface | 514.50E 4960.53N | FAA |
| Brunswick, ME | Surface | 425.02E 4859.12N | FAA |
| Portland, ME | Surface | 393.79E 4833.63N | NWS |
| Concord, NH | Surface | 296.88E 4785.84N | NWS |
| Burlington, VT | Surface | 169.88E 4931.87N | NWS |
| Otis Mill – Jay, ME | Surface | 404.85E 4925.29N | EPA AIRS |

| | | | |
|---|---|---|---|
| International Paper - Jay, ME | Surface | 402.28E 4928.08N | EPA AIRS |
| Boise Cascade, Rumford, ME | Surface | 377.05E 4934.48N | EPA AIRS |
| S.D. Warren – Westbrook, ME | Surface | 391.43E 4837.92N | EPA AIRS |
| Cape Elizabeth, ME | Surface | 402.45E 4823.59N | EPA AIRS |
| Burgess Tower, NH | Surface | 328.54E 4927.02N | EPA AIRS |
| **Hourly Sea Surface Station** | | | |
| Buoy #44007 Portland, ME | Buoy | 411.07E 4816.71N | NOAA |
| **Twice Daily Upper Air Stations** | | | |
| Portland, ME | All | 393.788E 4833.627N | NWS |
| Albany, NY | All | 107.130E 4744.023N | NWS |
| Chatham, MA | All | 420.912E 4613.028N | NWS |
| **Hourly Precipitation Observing Stations** | | | |
| Augusta, ME | Surface | 437.412E 4905.276N | NWS |
| Portland Int'l Jet Port, ME | Surface | 395.159E 4853.606N | NWS |
| Rumford 1 SSE, ME | Surface | 378.159E 4932.039N | NWS |
| Swans Falls, ME | Surface | 341.072E 4877.271N | NWS |
| Blackwater Dam Webster, NH | Surface | 279.698E 4799.350N | NWS |
| Bristol, NH | Surface | 280.725E 4830.818N | NWS |
| Errol, NH | Surface | 331.223E 4960.879N | NWS |
| Franklin Falls Dam, NH | Surface | 285.634E 4815.835N | NWS |
| Lincoln, NH | Surface | 286.373E 4880.668N | NWS |
| Littleton 3 NW, NH | Surface | 272.714E 4910.780N | NWS |
| Mt Washington, NH | Surface | 316.421E 4903.848N | NWS |
| North Durham 3 NNW, NH | Surface | 232.434E 4816.590N | NWS |
| North Stratford, NH | Surface | 291.546E 4958.336N | NWS |
| Pinkham Notch, NH | Surface | 320.412E 4903.737N | NWS |
| Warren 2 SSW, NH | Surface | 267.094E 4864.639N | NWS |
| St. Johnsbury, VT | Surface | 259.831E 4922.363N | NWS |
| **Ozone Monitoring Stations** | | | |
| Cape Elizabeth, ME | Surface | 398.112E 4823.655N | EPA AIRS |
| Hubbard Brook, NH | Surface | 283.041E 4868.879N | EPA AIRS |

### Table IV-2. CALMET Model Input Switches

| Parameter | Option(s) chosen |
|---|---|
| **INPUT GROUP 1 General run control parameters** | |
| **IRTYPE** Run Type 0 = Computes wind fields only. 1 = Computes wind fields and micrometeorological variables (u*, w*, L, zi, etc.) | IRTYPE = 1 |

| | |
|---|---|
| **LCALGRD** Compute special data fields required by CALGRID (i.e., 3-D fields of W wind components and temperature) in addition to regular fields? T=yes F=no | LCALGRD = T |
| **INPUT GROUP 5 Wind Field Options and Parameters**<br>**WIND FIELD OPTIONS** | |
| **IWFCOD** Model selection variable (0 = Objective analysis only 1 = Diagnostic wind module) | IWFCOD = 1 |
| **IFRADJ** Compute Froude number adjustment effects? (0=NO, 1=YES) | IFRADJ = 1 |
| **IKINE** Compute kinematic effects? (0=NO, 1=YES) | IKINE = 0 |
| **IOBR** Use O'Brien procedure for adjustment of the vertical velocity? (0=NO, 1=YES) | IOBR = 0 |
| **ISLOPE** Compute Slope flows? (0=NO, 1=YES) | ISLOPE = 1 |
| **IEXTRP** Extrapolate surface wind observations to upper layers?<br>1 = no extrapolation is done<br>-1 = same as above except layer 1 data at upper air stations are ignored | IEXTRP = -1 |
| **ICALM** Extrapolate calm winds aloft? (0=NO, 1=YES) | ICALM = 0 |
| **BIAS** Layer-dependent biases modifying the weights of surface and upper air stations. –1<=BIAS<=1 Zero BIAS leaves weights unchanged (1/R**2 interpolation) | BIAS(NZ) = 0,0,0,0,0,0,0,0,0,0 |
| **RMIN2** Minimum distance from nearest upper air station to surface station for which extrapolation of surface winds at surface station will be allowed. (Set to –1 for IEXTRP = 4 or other situations where all surface stations should be extrapolated) | RMIN2 = -1.0 |
| **IPROG** Use gridded prognostic wind field model output fields as input to the diagnostic wind field model. 4 = YES, use MM4 prognostic winds as initial guess field [IWFCOD = 1] | IPROG = 4 |
| **RADIUS OF INFLUENCE PARAMETERS** | |
| **LVARY** Use varying radius of influence (if no stations are found within RMAX1, RMAX2 or RMAX3, then the closest station will be used) T= yes F = no | LVARY = T |
| **RMAX1** Maximum radius of influence over land in the surface layer. Units: km | RMAX1 = 30. |
| **RMAX2** Maximum radius of influence over land aloft. Units: km | RMAX2 = 30. |
| **RMAX3** Maximum radius of influence over water. Units: km | RMAX3 = 50. |
| **OTHER WIND FIELD INPUT PARAMETERS** | |
| **RMIN** Minimum radius of influence used in the wind field interpolation. Units: km | RMIN = 0.1 |
| **TERRAD** Radius of influence of terrain features. Units: km | TERRAD = 12. |
| **R1** Relative weighting of the first guess field and observations in the SURFACE layer. (R1 is the distance from an observational station at which the observation and first guess field are equally weighted.) Units: km | R1 = 1. |
| **R2** Relative weighting of the first guess field and observations in the layers ALOFT. (R2 is applied in the upper layers in the same manner as R1 is used in the surface layer.) Units: km | R2 = 1. |
| **RPROG** Relative weighting parameter of the prognostic wind field data. (Used only if IPROG = 1) Units: km | RPROG = 0. |
| **DIVLIM** Maximum acceptable divergence in the divergence minimization procedure. | DIVLIM = 5.0E-06 |
| **NITER** Maximum number of iterations in the divergence minimization procedure. | NITER = 50 |
| **NSMTH** Number of passes in the smoothing procedure. (NZ values must be entered.) | NSMTH = 2,4,4,4,4,4,4,4,4,4 |
| **NINTR2** Maximum number of stations used in each layer for the interpolation of data to a grid point. (NZ values must be entered.) | NINTR2 = 5,5,5,5,5,5,5,5,5,5 |
| **CRITPN** Critical Froude number | CRITPN = 1. |
| **ALPHA** Empirical factor controlling the influence of kinematic effects. | ALPHA = 0.1 |
| **FEXTR2** Multiplicative scaling factor for extrapolation of surface observations to | FEXTR2 = |

| | |
|---|---|
| upper layers. (Used only if IEXTRP = 3 or –3) | 0.,0.,0.,0.,0.,0.,0.,0.,0.,0. |
| **BARRIER INFORMATION** | |
| **NBAR** Number of barriers to interpolation of the wind fields | NBAR = 0 |
| **DIAGNOSTIC MODULE DATA INPUT OPTIONS** | |
| **IDIOPT1** Surface temperature. 0 = Compute internally from hourly surface observations. 1 = Read preprocessed values from a data file (DIAG.DAT) | IDIOPT1 = 0 |
| **ISURFT** Surface meteorological station (Burlington, VT) to use for the surface temperature. (Must be a value from 1 to NSSTA) (Use only if IDIOPT1 = 0) | ISURFT = 9 |
| **IDIOPT2** Domain-averaged temperature lapse rate. 0 = Compute internally from twice-daily upper air observations. 1 = Read hourly preprocessed values from a data file (DIAG.DAT). | IDIOPT2 = 0 |
| **IUPT** Upper air station (Albany, NY) to use for the domain-scale lapse rate. (Must be a value from 1 to NUSTA) (Used only if IDIOPT2 = 0) | IUPT = 2 |
| **ZUPT** Depth through which the domain scale lapse rate is computed. (Used only if IDIOPT2 = 0) Units: meters | ZUPT = 200. |
| **IDIOPT3** Domain-averaged wind components. 0 = Compute internally from twice-daily upper air observations. 1 = Read hourly preprocessed values from a data file (DIAG.DAT) | IDIOPT3 = 0 |
| **IUPWND** Use spatially-variable initial guess field for the domain-scale winds. | IUPWND = -1 |
| **ZUPWND(1), ZUPWND(2)** Bottom and top of layer through which the domain-scale winds are computed. Units: meters | ZUPWND = 1., 1000. |
| **IDIOPT4** Observed surface wind components for wind field module. 0 = Read WS, WD from a surface data file (SURF.DAT) 1 = Read hourly preprocessed U, V from a data file (DIAG.DAT). | IDIOPT4 = 0 |
| **IDIOPT5** Observed upper air wind components for wind field module. 0 = Read WS, WD from an upper air data file (UP1.DAT, UP2.DAT, etc.) 1 = Read hourly preprocessed U, V from a data file (DIAG.DAT). | IDIOPT5 = 0 |
| **LAKE BREEZE INFORMATION** | |
| **LLBREEZE** Use Lake Breeze Module. T = Yes F = No | LLBREZE = F |
| **INPUT GROUP 6 Mixing Height, Temperature and Precipitation Parameters EMPIRICAL MIXING HEIGHT CONSTANTS** | |
| **CONSTB** Neutral, mechanical equation | CONSTB = 1.41 |
| **CONSTE** Convective mixing ht. Equation | CONSTE = 0.15 |
| **CONSTN** Stable mixing ht. Equation | CONSTN = 2400 |
| **CONSTW** Overwater mixing ht. Equation | CONSTW = 0.16 |
| **FCORIOL** Absolute value of Coriolis parameter. Units: (1/s) | FCORIOL = 1.0E-04 |
| **SPATIAL AVERAGING OF MIXING HEIGHTS** | |
| **IAVEZI** Conduct spatial averaging. (0=no, 1=yes) | IAVEZI = 1 |
| **MNMDAV** Max. search radius in averaging process. | MNMDAV = 10 |
| **HAFANG** Half-angle of upwind looking cone for averaging | HAFANG = 30. |
| **ILEVZI** Layer of winds (0-20m) used in upwind averaging. (Must be between 1 and NZ) | ILEVZI = 1 |
| **OTHER MIXING HEIGHT VARIABLES** | |
| **DPTMIN** Minimum potential temperature lapse rate in the stable layer above the current convective mixing ht. Units: deg. K/m | DPTMIN = 0.001 |
| **DZZI** Depth of layer above current convective mixing height through which lapse rate is computed. | DZZI = 200. |
| **ZIMIN** Minimum overland mixing height. | ZIMIN = 50. |

| | |
|---|---|
| **ZIMAX** Maximum overland mixing height. | ZIMAX = 2500. |
| **ZIMINW** Minimum overwater mixing height. (Not used if observed overwater mixing hts. are used.) | ZIMINW = 50. |
| **ZIMAXW** Maximum overwater mixing height. (Not used if observed overwater mixing hts. are used.) | ZIMAXW = 2500. |
| **TEMPERATURE PARAMETERS** | |
| **IRAD** Interpolation type (1 = 1/R ; 2 = 1/R**2) | IRAD = 1 |
| **TRADKM** Radius of influence for temperature interpolation. Units: km | TRADKM = 20. |
| **NUMTS** Maximum number of stations to include in temperature interpolation. | NUMTS = 5 |
| **IAVET** Conduct spatial averaging of temperatures. (0=no, 1=yes) | IAVET = 1 |
| **TGDEFB** Default temperature gradient below the mixing height over water (K/m) | TGDEFB = -0.0098 |
| **TGDEFA** Default temperature gradient above the mixing height over water (K/m) | TGDEFA = -0.0045 |
| **JWAT1, JWAT2** Beginning and ending land use categories for temperature interpolation over water. | JWAT1 = 55<br>JWAT2 = 55 |
| **PRECIP INTERPOLATION PARAMETERS** | |
| **NFLAGP** Method of interpolation. (1 = 1/R, 2 = 1/R**2, 3 = EXP/R**2) | NFLAGP = 2 |
| **SIGMAP** Radius of influence (km). | SIGMAP = 50. |
| **CUTP** Minimum precipitation rate cutoff (mm/hr) (Values < CUTP = 0.00 mm/hr) | CUTP = 0.01 |

Stack parameters used in the modeling for the proposed GELP facility, as well as off-site sources, are listed in Table IV-3. The modeling analyses accounted for the potential for building wake effects on emissions from the modeled stacks that are below their respective formula GEP stack height.

**Table IV-3. Stack Parameters**

| Facility/ Stack | Stack Base Elev (m) | Stack Height (m) | GEP Stack Height (m) | Stack Diameter (m) | UTM-E (km) | UTM-N (km) |
|---|---|---|---|---|---|---|
| **Part A. Current/Future** | | | | | | |
| **Gorham Energy, Gorham** | | | | | | |
| Stack 1 | 32.92 | 50.29 | 83.82 | 5.49 | 387.931 | 4838.752 |
| Stack 2 | 32.92 | 50.29 | 83.82 | 5.49 | 387.968 | 4838.797 |
| Stack 3 | 32.92 | 50.29 | 83.82 | 5.49 | 388.004 | 4838.841 |
| **Westbrook Power LLC, Westbrook** | | | | | | |
| Turbine Stack 1 | 30.48 | 50.29 | 80.01 | 5.49 | 388.910 | 4834.520 |
| Turbine Stack 2 | 30.48 | 50.29 | 80.01 | 5.49 | 388.920 | 4834.480 |
| **Fairchild Semiconductor, South Portland** | | | | | | |
| Boilers #3-6 | 18.59 | 33.53 | 39.17 | 0.4572 | 393.000 | 4832.560 |
| **National Semiconductor, South Portland** | | | | | | |
| Boilers #1-3 | 18.59 | 39.62 | 63.25 | 0.996 | 393.175 | 4832.510 |
| Boilers #4-6 | 18.59 | 39.62 | 63.25 | 0.996 | 393.178 | 4832.504 |
| **Central Maine Power – Wyman Station, Yarmouth** | | | | | | |
| Units #1, #2 & #5 | 7.90 | 97.54 | 128.57 | 3.02 | 406.900 | 4844.640 |
| Unit #3 | 7.90 | 97.54 | 128.57 | 3.09 | 406.900 | 4844.640 |
| Unit #4 | 7.90 | 129.54 | 143.76 | 7.50 | 406.890 | 4844.670 |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Maine Medical Center, Portland** | | | | | | |
| Main Stack | 43.59 | 38.10 | 93.92 | 1.52 | 397.04 | 4833.900 |
| **Burnham & Morrill, Portland** | | | | | | |
| Main Stack | 5.60 | 45.72 | 44.20 | 1.83 | 398.800 | 4836.660 |
| **SAPPI (S. D. Warren), Westbrook** | | | | | | |
| Boiler #21 | 13.11 | 109.70 | 109.70 | 3.20 | 390.860 | 4837.640 |
| Boilers #17-20 | 13.11 | 77.11 | 109.70 | 6.50 | 390.880 | 4837.640 |
| Recovery Boiler #3 | 13.11 | 76.20 | 109.70 | 2.74 | 390.940 | 4837.520 |
| Lime Kiln | 10.97 | 45.70 | 115.10 | 1.22 | 391.010 | 4837.630 |
| **Maine Correctional Center, South Windham** | | | | | | |
| Main Stack | 48.76 | 18.28 | 18.28 | 0.61 | 385.630 | 4840.240 |
| **Regional Waste Systems, South Portland** | | | | | | |
| Flue #1 | 12.80 | 66.45 | 76.20 | 1.22 | 392.360 | 4834.300 |
| Flue #2 | 12.80 | 66.45 | 76.20 | 1.22 | 392.360 | 4834.300 |
| **Part B. 1977 Baseline** | | | | | | |
| **National Semiconductor, South Portland** | | | | | | |
| Boilers #1-4 | 18.59 | 12.10 | 39.17 | 1.02 | 393.000 | 4832.560 |
| **Central Maine Power – Wyman Station, Yarmouth** | | | | | | |
| Units #1 & #2 | 7.90 | 97.54 | 128.57 | 3.02 | 406.900 | 4844.640 |
| Unit #3 | 7.90 | 97.54 | 128.57 | 3.09 | 406.900 | 4844.640 |
| **Maine Medical Center, Portland** | | | | | | |
| Boiler #1 | 43.59 | 24.40 | 93.93 | 1.37 | 397.020 | 4833.880 |
| Boilers #2 & #3 | 43.59 | 38.10 | 93.93 | 1.52 | 397.040 | 4833.900 |
| **Burnham & Morrill, Portland** | | | | | | |
| Main Stack | 5.60 | 45.72 | 44.20 | 1.83 | 398.800 | 4836.660 |
| **S. D. Warren, Westbrook** | | | | | | |
| Boilers #17-20 | 13.11 | 107.60 | 109.70 | 6.50 | 390.880 | 4837.640 |
| Recovery Boiler #2 | 13.11 | 49.40 | 109.70 | 2.74 | 390.940 | 4837.520 |
| Lime Kiln | 10.97 | 18.59 | 115.10 | 1.22 | 391.010 | 4837.630 |
| **Part C. 1987 Baseline** | | | | | | |
| **National Semiconductor, South Portland** | | | | | | |
| Boilers #1-4 | 18.59 | 33.53 | 39.17 | 0.4572 | 393.000 | 4832.560 |
| **Maine Medical Center, Portland** | | | | | | |
| Boiler #1 | 43.59 | 24.40 | 93.93 | 1.37 | 397.020 | 4833.880 |
| Boilers #2 & #3 | 43.59 | 38.10 | 93.93 | 1.52 | 397.040 | 4833.900 |
| **Burnham & Morrill, Portland** | | | | | | |
| Main Stack | 5.60 | 45.72 | 44.20 | 1.83 | 398.800 | 4836.660 |
| **S. D. Warren, Westbrook** | | | | | | |
| Boiler #21 | 13.11 | 109.70 | 109.70 | 3.20 | 390.860 | 4837.640 |
| Boilers #17-20 | 13.11 | 107.60 | 109.70 | 5.49 | 390.880 | 4837.640 |
| Recovery Boiler #2 | 13.11 | 49.40 | 109.70 | 1.83 | 390.940 | 4837.520 |
| Lime Kiln | 10.97 | 18.59 | 115.10 | 1.22 | 391.010 | 4837.630 |

Emission parameters for GELP's three stacks and other sources for MAAQS and increment modeling are listed in Table IV-4. Each stack will exhaust emissions from a combustion turbine, heat recovery steam generator (HRSG) and a steam turbine. Proposed fuels to be used include natural gas and 0.05%S distillate oil. Operation of any unit will be limited to between 75% and 100% of its design load. Worst case dispersive conditions were chosen for the exhaust emissions, where the 0°F ambient temperature scenario for emission rates and exit temperatures and the 90°F ambient temperature scenario for exit velocities were modeled. For the purpose of determining $PM_{10}$ impacts, all PM emissions were conservatively assumed to convert to $PM_{10}$. For the purpose of determining $NO_2$ impacts in the SCREEN3, CIVM and ISCST3 modeling analyses, all $NO_x$ emissions were conservatively assumed to convert to $NO_2$. For the purpose of determining $NO_2$ impacts in the CALPUFF modeling analyses, all $NO_x$ emissions were conservatively assumed to convert to 90% NO and 10% $NO_2$ adjusted for the molecular weight difference (molecular weights of NO and $NO_2$ are 30 and 46, respectively) between the two species using the following formulas:

NO emis/rate = $NO_x$ (weighed as $NO_2$) * 0.90 * (30/46)
$NO_2$ emis/rate = $NO_x$ (weighed as $NO_2$) * 0.10 * (46/46)

The molecular weight adjustment was made because CALPUFF automatically accounts for the molecular weight change in the NO to $NO_2$ conversion.

**Table IV-4. Emission Parameters**

| Facility/Stack (Operating Scenario | Averaging Period(s) | Emis/Rate $SO_2$ (g/s) | Emis/Rate PM (g/s) | Emis/Rate $NO_x$ (NO / $NO_2$) (g/s) | Emis/Rate CO (g/s) | Temp (°K) | Stack Vel. (m/s) |
|---|---|---|---|---|---|---|---|
| **Part A. Maximum Licensed Allowed** | | | | | | | |
| **Gorham Energy, Gorham Proposed Operating Scenarios** | | | | | | | |
| **75% Natural Gas w/o Steam Injection** | | | | | | | |
| Stack 1, 2 or 3 | All | 0.441 | 2.394 | 2.520 (1.479/0.252) | 2.268 | 347.59 | 14.19 |
| **100% Natural Gas w/o Steam Injection** | | | | | | | |
| Stack 1, 2 or 3 | All | 0.5544 | 3.024 | 3.150 (1.849/0.315) | 2.772 | 357.04 | 16.84 |
| **100% Natural Gas with Steam Injection** | | | | | | | |
| Stack 1, 2 or 3 | All | 0.6048 | 3.276 | 3.528 (2.071/0.353) | 3.024 | 353.15 | 17.75 |
| **100% No. 2 Fuel Oil w/o Steam Injection** | | | | | | | |
| Stack 1, 2 or 3 | All | 13.608 | 12.726 | 9.450 (5.547/0.945) | 6.426 | 447.59 | 20.39 |
| **75% No. 2 Fuel Oil w/o Steam Injection** | | | | | | | |
| Stack 1, 2 or 3 | All | 10.962 | 11.466 | 7.560 (4.437/0.756) | 5.166 | 422.04 | 16.02 |
| **Westbrook Power LLC, Westbrook** | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Turb. Stack 1 | All | 1.47 | 1.39 | 3.15 | n/a | 351.00 | 21.02 |
| Turb. Stack 2 | All | 1.47 | 1.39 | 3.15 | n/a | 351.00 | 21.02 |
| **Fairchild Semiconductor, South Portland** | | | | | | | |
| Boilers #3-6 | All | 5.15 | 0.99 | 2.97 | n/a | 438.70 | 68.40 |
| **National Semiconductor, South Portland** | | | | | | | |
| Boilers #1-3 | All | 5.76 | 1.11 | 2.21 | n/a | 394.30 | 14.55 |
| Boilers #4-6 | All | 5.76 | 1.11 | 2.21 | n/a | 394.30 | 14.55 |
| **Central Maine Power – Wyman Station, Yarmouth** | | | | | | | |
| Units #1 #2 #5 | All | 439.72 | 50.34 | 74.62 | n/a | 484.00 | 36.55 |
| Unit #3 | All | 392.84 | 44.98 | 44.98 | n/a | 445.00 | 28.08 |
| Unit #4 | All | 634.03 | 79.26 | 237.76 | n/a | 489.00 | 22.68 |
| **Maine Medical Center, Portland** | | | | | | | |
| Main Stack | All | 6.51 | 2.77 | 6.94 | n/a | 450.00 | 8.67 |
| **Burnham & Morrill, Portland** | | | | | | | |
| Main Stack | All | 8.63 | 0.6174 | 0.81 | n/a | 450.00 | 2.22 |
| **SAPPI (S. D, Warren), Westbrook** | | | | | | | |
| Boiler #21 | All | 162.40 | 10.80 | 51.40 | n/a | 485.00 | 28.50 |
| Boilers #17-20 | All | 67.50 | 17.60 | 27.90 | n/a | 450.00 | 4.69 |
| Rec. Boiler #3 | All | 19.80 | 2.40 | 8.80 | n/a | 433.00 | 12.80 |
| Lime Kiln | All | 0.53 | 1.29 | 2.60 | n/a | 342.00 | 6.13 |
| **Maine Correctional Center, South Windham** | | | | | | | |
| Main Stack | All | 2.21 | 0.25 | 1.05 | n/a | 450.00 | 6.50 |
| **Regional Waste Systems, South Portland** | | | | | | | |
| Flue #1 | All | n/a | n/a | 4.95 | n/a | 422.04 | 20.12 |
| Flue #2 | All | n/a | n/a | 4.95 | n/a | 422.04 | 20.12 |
| **Part B. 1977 Baseline Actual** | | | | | | | |
| **National Semiconductor, South Portland** | | | | | | | |
| Boilers #1-4 | Short term | 6.40 | 0.60 | n/a | n/a | 450.00 | 4.00 |
| | Annual | 5.40 | 0.50 | n/a | n/a | 450.00 | 3.00 |
| **Central Maine Power – Wyman Station, Yarmouth** | | | | | | | |
| Units #1 & #2 | Short term | 231.86 | 26.55 | n/a | n/a | 484.00 | 17.56 |
| | Annual | 91.49 | 10.48 | n/a | n/a | 409.00 | 12.29 |
| Unit #3 | Short term | 262.33 | 30.04 | n/a | n/a | 433.00 | 18.75 |
| | Annual | 209.76 | 24.02 | n/a | n/a | 422.00 | 15.20 |
| **Maine Medical Center, Portland** | | | | | | | |
| Boiler #1 | Short term | 4.01 | 0.49 | n/a | n/a | 450.00 | 1.90 |
| | Annual | 2.64 | 0.33 | n/a | n/a | 450.00 | 1.33 |
| Boilers #2 #3 | Short term | 0.73 | 0.09 | n/a | n/a | 450.00 | 0.28 |
| | Annual | 0.68 | 0.08 | n/a | n/a | 450.00 | 0.26 |
| **Burnham & Morrill, Portland** | | | | | | | |
| Main Stack | Short term | 13.06 | 0.93 | n/a | n/a | 450.00 | 2.22 |
| | Annual | 3.76 | 0.27 | n/a | n/a | 450.00 | 0.76 |
| **S. D, Warren, Westbrook** | | | | | | | |
| Boilers #17-20 | All | 209.70 | 17.25 | n/a | n/a | 450.00 | 5.35 |
| Rec. Boiler #2 | Short term | 60.20 | 5.20 | n/a | n/a | 377.00 | 21.93 |
| | Annual | 51.30 | 3.20 | n/a | n/a | 377.00 | 21.93 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Lime Kiln | All | 0.32 | 0.65 | n/a | n/a | 341.50 | 6.91 |
| **Part C. 1987 Baseline Actual** | | | | | | | |
| **National Semiconductor, South Portland** | | | | | | | |
| Boilers #1-4 | Annual | n/a | n/a | 0.70 | n/a | 450.00 | 15.90 |
| **Maine Medical Center, Portland** | | | | | | | |
| Boiler #1 | Annual | n/a | n/a | 0.58 | n/a | 450.00 | 0.99 |
| Boilers #2 #3 | Annual | n/a | n/a | 0.49 | n/a | 450.00 | 0.68 |
| **Burnham & Morrill, Portland** | | | | | | | |
| Main Stack | Annual | n/a | n/a | 0.75 | n/a | 450.00 | 0.72 |
| **S. D, Warren, Westbrook** | | | | | | | |
| Boiler #21 | Annual | n/a | n/a | 77.53 | n/a | 391.00 | 23.53 |
| Boilers #17-20 | Annual | n/a | n/a | 5.46 | n/a | 427.00 | 4.35 |
| Rec. Boiler #2 | Annual | n/a | n/a | 3.72 | n/a | 378.00 | 22.10 |
| Lime Kiln | Annual | n/a | n/a | 1.20 | n/a | 342.00 | 6.91 |

Note:
n/a Not Applicable

C. Applicant's modeled impacts

SCREEN3 (Valley Mode) and refined ISCST3 (Simple Terrain Mode) modeling analyses were performed for the five (5) GELP operating scenarios listed in Table IV-4. Results in Table IV-5 and Table IV-6 show impacts that are greater than Class II significance levels for short term $SO_2$ and $PM_{10}$ averaging periods in simple terrain and for all $SO_2$, $PM_{10}$ and $NO_2$ averaging periods in intermediate and complex terrain. No further Class II MAAQS modeling of 1-hour and 8-hour CO averaging periods in complex terrain or annual $SO_2$, $PM_{10}$ and $NO_2$ in simple terrain is needed because all modeled impacts for those averaging periods were below the respective Class II significant impact levels.

Table IV-5. Maximum ISCST3 (Simple Terrain Mode) Simple and Intermediate Terrain Impacts From GELP Alone.

| **Pollutant/ Averaging Period** | **GELP Max Impact (µg/m³)** | **Max Impact Receptor** | | | **De Minimus Level (µg/m³)** | **Class II Sig. Level (µg/m³)** | **Class II Increment (µg/m³)** |
|---|---|---|---|---|---|---|---|
| | | **UTM-E (km)** | **UTM-N (km)** | **Elevation (m)** | | | |
| **Natural Gas Operating Scenarios** | | | | | | | |
| $SO_2$ 3-hour | 2.99* | 388.500 | 4838.500 | 48.77 | **n/a** | **25** | **512** |
| $SO_2$ 24-hour | 0.95* | 388.250 | 4838.500 | 42.67 | **13** | **5** | **91** |
| $SO_2$ Annual | 0.057* | 388.000 | 4843.000 | 97.54 | **n/a** | **1** | **20** |
| $PM_{10}$ 24-hour | **5.16*** | 388.250 | 4838.500 | 42.67 | **10** | **5** | **30** |
| $PM_{10}$ Annual | 0.31* | 388.000 | 4843.000 | 97.54 | **n/a** | **1** | **17** |
| $NO_2$ Annual | 0.33** | 388.000 | 4843.000 | 97.54 | **14** | **1** | **25** |
| CO 1-hour | 27.51* | 390.000 | 4838.750 | 79.25 | **n/a** | **2000** | **n/a** |
| CO 8-hour | 8.81* | 388.250 | 4838.500 | 42.67 | **575** | **500** | **n/a** |
| **0.05% Distillate Oil Operating Scenarios** | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| $SO_2$ 3-hour | **42.25^** | 388.500 | 4838.500 | 48.77 | **n/a** | **25** | **512** |
| $SO_2$ 24-hour | **13.29^** | 388.250 | 4838.500 | 42.67 | **13** | **5** | **91** |
| $SO_2$ Annual | 0.63^ | 388.000 | 4843.000 | 97.54 | **n/a** | **1** | **20** |
| $PM_{10}$ 24-hour | **13.90^** | 388.250 | 4838.500 | 42.67 | **10** | **5** | **30** |
| $PM_{10}$ Annual | 0.65^ | 388.000 | 4843.000 | 97.54 | **n/a** | **1** | **17** |
| $NO_2$ Annual | 0.43^ | 388.000 | 4843.000 | 97.54 | **14** | **1** | **25** |
| CO 1-hour | 25.14^ | 388.250 | 4838.500 | 42.67 | **n/a** | **2000** | **n/a** |
| CO 8-hour | 11.77^ | 388.250 | 4838.500 | 42.67 | **575** | **500** | **n/a** |

Notes:
n/a Not Applicable
* 75% (3-stacks) natural gas w/o steam injection operating scenario
** 100% (3-stacks) natural gas with steam injection operating scenario
^ 75% (3-stacks) oil w/o steam injection operating scenario

**Table IV-6. Maximum GELP Alone SCREEN3 (Valley) Intermediate and Complex Terrain Impacts.**

| Pollutant/ Averaging Period | GELP Max Impact (µg/m³) | Max Impact Receptor Distance (km) | Elevation (m) | De Minimus Level (µg/m³) | Class II Sig. Level (µg/m³) | Class II Increment (µg/m³) |
|---|---|---|---|---|---|---|
| **Natural Gas Operating Scenarios** | | | | | | |
| $SO_2$ 3-hour | 2.34* | 7.25 | 146.32 | **n/a** | **25** | **512** |
| $SO_2$ 24-hour | 0.65* | 7.25 | 146.32 | **13** | **5** | **91** |
| $SO_2$ Annual | 0.21* | 7.25 | 146.32 | **n/a** | **1** | **20** |
| $PM_{10}$ 24-hour | 3.52* | 7.25 | 146.32 | **10** | **5** | **30** |
| $PM_{10}$ Annual | **1.13*** | 7.25 | 146.32 | **n/a** | **1** | **17** |
| $NO_2$ Annual | **1.21*** | 7.25 | 146.32 | **14** | **1** | **25** |
| CO 1-hour | 12.99* | 7.25 | 146.32 | **n/a** | **2000** | **n/a** |
| CO 8-hour | 9.09* | 7.25 | 146.32 | **575** | **500** | **n/a** |
| **0.05% Distillate Oil Operating Scenarios** | | | | | | |
| $SO_2$ 3-hour | **29.09^** | 7.25 | 146.32 | **n/a** | **25** | **512** |
| $SO_2$ 24-hour | **8.08^** | 7.25 | 146.32 | **13** | **5** | **91** |
| $SO_2$ Annual | **2.59^** | 7.25 | 146.32 | **n/a** | **1** | **20** |
| $PM_{10}$ 24-hour | **8.45^** | 7.25 | 146.32 | **10** | **5** | **30** |
| $PM_{10}$ Annual | **2.71^** | 7.25 | 146.32 | **n/a** | **1** | **17** |
| $NO_2$ Annual | **1.78^** | 7.25 | 146.32 | **14** | **1** | **25** |
| CO 1-hour | 15.23^ | 7.25 | 146.32 | **n/a** | **2000** | **n/a** |
| CO 8-hour | 10.66^ | 7.25 | 146.32 | **575** | **500** | **n/a** |

Notes:
n/a Not Applicable
* 100% (3-stacks) natural gas with steam injection operating scenario
^ 75% (3-stacks) oil w/o steam injection operating scenario

D. Combined Source Modeling

Proposed GELP emissions were shown to have significant impacts for $SO_2$, $PM_{10}$ and $NO_2$ in Class II areas. Thus, other sources not explicitly included in the modeling analyses were included by using representative background concentrations for the area. Conservative Southern Maine rural background concentrations were used and are based on existing (1994 to 1996) PEOPL site monitoring data reported by the MEDEP-BAQ Field Services Division. These background values are listed in Table IV-7.

Table IV-7. Background concentrations (µg/m³)

| Pollutant | Avg. Time | Urban Concentration |
|---|---|---|
| $SO_2$ | 3-hour | 159[1] |
| | 24-hour | 119[1] |
| | Annual | 20[1] |
| $PM_{10}$ | 24-hour | 49[1] |
| | Annual | 21[1] |
| $NO_2$ | Annual | 26 (1992)[1] |

Note:
1 Portland PEOPL Site

As the applicant's $SO_2$, $PM_{10}$ and $NO_2$ impacts were significant, other sources needed to be considered in the final modeling demonstration. MEDEP-BAQ identified the following nine sources to be included in the MAAQS and Class II modeling analyses:

- Westbrook Power LLC, Westbrook
- Fairchild Semiconductor, South Portland
- National Semiconductor, South Portland
- Central Maine Power – Wyman Station, Yarmouth
- Maine Medical Center, Portland
- Burnham & Morrill, Portland
- SAPPI (S. D, Warren), Westbrook
- Maine Correctional Center, South Windham
- Regional Waste Systems, South Portland

The ISCST3 (Simple Terrain Mode) model, using the five (5) year meteorological database, was used to determine the combined source maximum short term $SO_2$ and $PM_{10}$ impacts. Results when added to background, as shown in Table IV-8, shows compliance with short term $SO_2$ and $PM_{10}$ averaging period MAAQS.

**Table IV-8. Maximum Combined Source ISCST3 (Simple Terrain Mode) Impacts**

| Pollutant/ Averaging Period | Max Impact (μg/m³) | Max. Impact Receptor Location UTM-E (km) | UTM-N (km) | Elevation (m) | Back-ground (μg/m³) | Total Impact (μg/m³) | MAAQS (μg/m³) |
|---|---|---|---|---|---|---|---|
| $SO_2$ 3-hour | 286.62 | 392.000 | 4845.000 | 128.02 | **159** | 445.62 | **1150** |
| $SO_2$ 24-hour | 66.10 | 390.500 | 4837.500 | 30.48 | **119** | 185.10 | **230** |
| $PM_{10}$ 24-hour | 16.84 | 390.500 | 4837.500 | 30.48 | **49** | 65.84 | **150** |

The CIVM screening model was used to determine the combined source maximum annual and short term $SO_2$, $PM_{10}$ and $NO_2$ averaging period impacts. Results when added to background, as shown in Table IV-9, show all combined 3-hour $SO_2$, 24-hour and annual $PM_{10}$ and annual $NO_2$ averaging period impacts from the applicant's proposed facility and other sources including background were below their respective MAAQS. However, there was one modeled violation of the 24-hour $SO_2$ MAAQS and one modeled violation of the annual $SO_2$ MAAQS using the conservative background value in Table IV-7. The applicant's contribution to both of those modeled violations was below the annual and 24-hour $SO_2$ Class II significance levels. Therefore, results of the ISCST3 and CIVM modeling analyses demonstrate that the applicant's facility does not cause or contribute to a violation of any $SO_2$, $PM_{10}$, $NO_2$ or CO averaging period MAAQS.

***Table IV-9. Maximum Combined Source CIVM Intermediate/Complex Terrain Impacts***

| Pollutant/ Averaging Period | Max Impact (μg/m³) | GELP Contrib. Impact (μg/m³) | Class II Sig. Level (μg/m³) | Maximum Impact Receptor Location UTM-E (km) | UTM-N (km) | Elev. (m) | Back-Ground (μg/m³) | Total Impact (μg/m³) | MAAQS (μg/m³) |
|---|---|---|---|---|---|---|---|---|---|
| $SO_2$ 3-hour | 422.81 | 0.00 | 25 | 394.000 | 4846.000 | 152.40 | **159** | 581.81 | **1150** |
| $SO_2$ 24-hour | **117.45** | 0.00 | 5 | 394.000 | 4846.000 | 152.40 | **119** | **236.45** | **230** |
| | 101.22 | 0.00 | 5 | 391.000 | 4851.000 | 158.50 | **119** | 220.22 | **230** |
| $SO_2$ Annual | **37.58** | 0.00 | 1 | 394.000 | 4846.000 | 152.40 | **20** | **57.58** | **230** |
| | 32.39 | 0.00 | 1 | 391.000 | 4851.000 | 158.50 | **20** | 52.39 | **57** |
| $PM_{10}$ 24-hour | 16.67 | **7.48*** | 5 | 394.000 | 4846.000 | 152.40 | **49** | 65.67 | **150** |
| $PM_{10}$ Annual | 5.33 | **2.39*** | 1 | 394.000 | 4846.000 | 152.40 | **21** | 26.33 | **40** |
| $NO_2$ Annual | 30.07 | 0.00 | 1 | 393.000 | 4844.000 | 146.30 | **26** | 56.07 | **100** |

Note:
* 75% (3-stacks) oil w/o steam injection operating scenario

E. Class II Increment

Table IV-10 and Table IV-11 summarize the combined source $SO_2$, $PM_{10}$ and $NO_2$ increment impacts in Class II areas using the same approach used in the MAAQS compliance demonstration. Results show all combined 3-hour and 24-hour $SO_2$, 24-hour and annual $PM_{10}$ and annual $NO_2$ averaging period increment from the applicant's proposed facility and other sources were below the respective Class II increment. However, there was one modeled violation of the annual $SO_2$ increment standard. The applicant's contribution to this modeled violation was below the annual $SO_2$ Class II significance level. Therefore, results of the ISCST3 and CIVM modeling analyses demonstrate that the applicant's facility does not cause or contribute to a violation of any $SO_2$, $PM_{10}$ or $NO_2$ averaging period Class II increment.

Table IV-10. Maximum Combined Source ISCST3 (Simple Terrain Mode) Increment Consumption in Class II Areas

| **Pollutant/ Averaging Period** | **Max Impact (µg/m³)** | **Maximum Impact Receptor Location** | | | **Class II Increment (µg/m³)** |
|---|---|---|---|---|---|
| | | **UTM-E (km)** | **UTM-N (km)** | **Elevation (m)** | |
| $SO_2$ 3-hour | 161.52 | 391.000 | 4837.500 | 18.29 | **512** |
| $SO_2$ 24-hour | 47.27 | 391.000 | 4837.500 | 18.29 | **91** |
| $PM_{10}$ 24-hour | 13.26 | 391.000 | 4837.500 | 18.29 | **30** |

Table IV-11. Maximum Combined Source CIVM Intermediate/Complex Terrain Increment Consumption in Class II Areas

| **Pollutant/ Averaging Period** | **Max Impact (µg/m³)** | **GELP Contrib. Impact (µg/m³)** | **Class II Sig. Level (µg/m³)** | **Maximum Impact Receptor Location** | | | **Class II Increment (µg/m³)** |
|---|---|---|---|---|---|---|---|
| | | | | **UTM-E (km)** | **UTM-N (km)** | **Elevation (m)** | |
| $SO_2$ 3-hour | 235.71 | 0.00 | **25** | 394.000 | 4846.000 | 152.40 | **512** |
| $SO_2$ 24-hour | 65.48 | 0.00 | **5** | 394.000 | 4846.000 | 152.40 | **91** |
| $SO_2$ Annual | **20.95** | 0.00 | **1** | 394.000 | 4846.000 | 152.40 | **20** |
| | 19.34 | 0.00 | **1** | 391.000 | 4851.000 | 158.50 | **20** |
| $PM_{10}$ 24-hour | 11.00 | **7.48*** | **5** | 394.000 | 4846.000 | 152.40 | **30** |
| $PM_{10}$ Annual | 3.52 | **2.39*** | **1** | 394.000 | 4846.000 | 152.40 | **17** |
| $NO_2$ Annual | 5.85 | 0.00 | **1** | 394.000 | 4846.000 | 152.40 | **25** |

Note:
* 75% oil operating scenario

F. Additional Class II Impact Analyses

Federal guidance and Chapters 115 and 140 of the MEDEP-BAQ regulations require that any new major source provide additional analyses of impacts that would occur as a direct result of the general, commercial, residential, industrial and other growth associated with the construction and operation of that source. In addition, an analysis of impairment to visibility, soils and vegetation that would occur as a result of any new major source is required.

**GENERAL GROWTH:** Some increases in local emissions due to construction related activities are expected to occur. Emissions of dust from construction related activities will be minimized by the use of Best Management Practices for construction on site. Increases in potential emissions of $NO_x$ due to commuting by construction workers will be temporary and short-lived.

**RESIDENTIAL GROWTH:** Population growth in the impact area of the proposed source can be used as a surrogate factor for the growth in emissions from residential combustion sources. GELP is expected to create approximately 15 new full-time jobs as a result of this proposed project. However, it is expected that the available local work force will be able to fill in some of these positions. Thus, no new significant residential growth will follow from this new source.

**COMMERCIAL, INDUSTRIAL and OTHER GROWTH:** The proposed project will be constructed for the sale of electricity only. Since the proposed project will consume very little in terms of raw materials and supplies, construction of new industries and businesses to support the facility's operation will likely not be needed, therefore, no significant commercial, industrial or other growth is expected to occur as a result of this project.

**CLASS II VISIBILITY:** Class II visible emissions from the proposed facility will be minimized by controlling emissions through the implementation of BACT which includes the combustion of clean fuels (i.e. low sulfur oil and natural gas).

**SOILS AND VEGETATION:** Impacts on sensitive vegetation and soils were evaluated using the maximum impacts from the ISCST3 and SCREEN3 modeling analyses. The results of the soil and vegetation impacts are shown in Table IV-12. Evaluation of impacts on sensitive vegetation and soils was performed by comparison of predicted facility impacts with screening levels presented in *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals* (EPA, December, 1980, EPA 450/2-81-078). Any acute or chronic deleterious effects to the soils and vegetation would be expected to occur only at ambient concentration levels substantially higher than impacts predicted by dispersion modeling. Proposed emissions from GELP's proposed facility are not expected to impact even the more sensitive soil or vegetation near the facility. Because the soil and vegetation impacts near the facility (non-Class I areas) are well below the vegetation sensitivity levels, impacts in Class I areas were not evaluated.

**TABLE IV-12. Soil and Vegetation Impacts, GELP Alone**

| Pollutant | Averaging Period | Max GELP Class II Impact ($\mu g/m^3$) | Sensitivity Screening Levels ($\mu g/m^3$) |
|---|---|---|---|
| **$SO_2$** | 1-hour | < 130[1] | 917 |
| | 3-hour | 42.25[1] | 786 |
| | Annual | 2.59[1] | 18 |
| **$NO_2$** | 4-hour | 20.06[2] | 3760 |
| | 8-hour | 15.60[2] | 3760 |
| | 1-Month | 5.57[2] (24-hour) | 564 |
| | Annual | 1.78[2] | 94 |
| **CO** | 1-Week | 27.51[1] (8-hour) | 1,800,000 |

Notes:
[1] = Maximum ISCST3 impact from GELP alone.
[2] = Maximum SCREEN3 Valley impact from GELP alone

G. Class I Increment Analysis

The New Hampshire Great Gulf Wilderness (GGW) and the Presidential Range-Dry River Wilderness (PRDRW) Class I areas are located approximately 94 km and 84km, respectively from the proposed GELP facility. All other Class I areas in Maine are located well beyond 100 kilometers from the proposed GELP facility. Class I analyses for Acadia National Park, Moosehorn National Wildlife Refuge and Roosevelt Campobello International Park Class I areas were not performed because the GELP facility will be located at a distance well beyond 100 kilometers from those Class I areas and MEDEP does not consider the proposed source emissions (after required $NO_x$ offsets and $SO_2$ allowances) to be in the category warranting Class I analyses beyond 100 kilometers. Therefore, a Class I increment analysis was only performed for the GGW and PRDRW Class I areas.

Because all receptors in the GGW and PRDRW Class I areas are in complex terrain, the VALLEY mode of the SCREEN3 model was first used to determine Class I increment impacts from the proposed GELP facility emissions. Results in Table IV-13 show that all $SO_2$, $PM_{10}$ and $NO_2$ averaging period Class I increment impacts were below their respective significance levels (< 4% of Class I increment) for operating scenarios with natural gas. Therefore, no further Class I increment analysis is required for the natural gas operating scenarios.

Results (not shown in Table IV-13) of the SCREEN3 VALLEY $SO_2$, $PM_{10}$ and $NO_2$ Class I increment analyses for the 0.05% distillate oil operating scenarios show that all $SO_2$, $PM_{10}$ and $NO_2$ averaging period Class I increment impacts are above Class I significance levels. Therefore, other sources must be included in the analysis or a more refined modeling technique shall be utilized.

The CALPUFF model was utilized using one year (1990) of processed CALMET meteorological data. Because the CALPUFF/CALMET/CALPOST modeling system is not an Appendix A model with mandatory regulatory options, sound meteorological judgment needs to be used to select the most appropriate model options. Table IV-14 summarizes options (with the exception of stack parameters, emission parameters, and receptors) used in the GELP CALPUFF Class I Increment analysis.

Results of the CALPUFF analysis for the oil operating scenarios are shown in Table IV-13. For the oil operating scenarios with 3 stacks in operation all short term $SO_2$ and $PM_{10}$ averaging period impacts are still above the respective Class I significance levels. For the oil operating scenarios with 2 stacks in operation, only the 100% operating scenario 24-hour $SO_2$ averaging period impact is above the respective Class I significance level. For the oil operating scenarios with 1 stack in operation, all $SO_2$, $PM_{10}$ and $NO_2$ averaging period impacts were below the respective Class I significance levels. As a result, either other sources must be included in the analysis or a license restriction will be needed. The applicant has chosen at this time to propose the following license restrictions:

- 0.05%S distillate oil may not be fired in more than two generation units simultaneously. When firing oil in two generation units simultaneously, neither unit shall be operated in excess of 75% of its design capacity.

- When firing 0.05%S distillate oil in only one generation unit, such unit may be fired at any load between 75% and 100% of its design capacity.

Table IV-13. Maximum Increment Consumption in Class I Areas from GELP.

| **Pollutant/ Averaging Period** | **Max Impact (µg/m³)** | **Model Used** | **Class I Sig. Level (µg/m³)** | **Maximum Impact Operating Scenario** | **Class I Increment (µg/m³)** |
|---|---|---|---|---|---|
| **OPERATING SCENARIOS WITH NATURAL GAS (3 units operating)** | | | | | |
| $SO_2$ 3-hour | 0.166 | SCREEN3 | **1.0** | **100% with Steam Injection** | **25** |
| $SO_2$ 24-hour | 0.046 | SCREEN3 | **0.2** | **100% with Steam Injection** | **5** |
| $SO_2$ Annual | 0.015 | SCREEN3 | **0.08** | **100% with Steam Injection** | **2** |
| $PM_{10}$ 24-hour | 0.250 | SCREEN3 | **0.32** | **100% with Steam Injection** | **8** |
| $PM_{10}$ Annual | 0.080 | SCREEN3 | **0.16** | **100% with Steam Injection** | **4** |
| $NO_2$ Annual | 0.086 | SCREEN3 | **0.1** | **100% with Steam Injection** | **2.5** |
| **OPERATING SCENARIOS WITH DISTILLATE OIL (0.05%S) (3-units operating)** | | | | | |
| $SO_2$ 3-hour | **1.33*** | CALPUFF | **1.0** | **100% Distillate Oil (0.05%S)** | **25** |
| $SO_2$ 24-hour | **0.35*** | CALPUFF | **0.2** | **100% Distillate Oil (0.05%S)** | **5** |
| $SO_2$ Annual | 0.008 | CALPUFF | **0.08** | **100% Distillate Oil (0.05%S)** | **2** |
| $PM_{10}$ 24-hour | **0.41*** | CALPUFF | **0.32** | **100% Distillate Oil (0.05%S)** | **8** |
| $PM_{10}$ Annual | 0.007 | CALPUFF | **0.16** | **100% Distillate Oil (0.05%S)** | **4** |
| $NO_2$ Annual | 0.005 | CALPUFF | **0.1** | **100% Distillate Oil (0.05%S)** | **2.5** |
| **OPERATING SCENARIOS WITH DISTILLATE OIL (0.05%S) (2-units operating)** | | | | | |
| $SO_2$ 3-hour | 0.93<br>0.67 | CALPUFF<br>CALPUFF | **1.0**<br>**1.0** | **100% Distillate Oil (0.05%S)**<br>**75% Distillate Oil (0.05%S)** | **25** |
| $SO_2$ 24-hour | **0.24**<br>0.18 | CALPUFF<br>CALPUFF | **0.2**<br>**0.2** | **100% Distillate Oil (0.05%S)**<br>**75% Distillate Oil (0.05%S)** | **5** |
| $SO_2$ Annual | 0.005<br>0.004 | CALPUFF<br>CALPUFF | **0.08**<br>**0.08** | **100% Distillate Oil (0.05%S)**<br>**75% Distillate Oil (0.05%S)** | **2** |
| $PM_{10}$ 24-hour | 0.28<br>0.24 | CALPUFF<br>CALPUFF | **0.32**<br>**0.32** | **100% Distillate Oil (0.05%S)**<br>**75% Distillate Oil (0.05%S)** | **8** |
| $PM_{10}$ Annual | 0.005<br>0.005 | CALPUFF<br>CALPUFF | **0.16**<br>**0.16** | **100% Distillate Oil (0.05%S)**<br>**75% Distillate Oil (0.05%S)** | **4** |
| $NO_2$ Annual | 0.003<br>0.003 | CALPUFF<br>CALPUFF | **0.1**<br>**0.1** | **100% Distillate Oil (0.05%S)**<br>**75% Distillate Oil (0.05%S)** | **2.5** |

| | | | | | |
|---|---|---|---|---|---|
| **OPERATING SCENARIOS WITH DISTILLATE OIL (0.05%S) (1-units operating)** | | | | | |
| $SO_2$ 3-hour | 0.44 | CALPUFF | **1.0** | **100% Distillate Oil (0.05%S)** | **25** |
| $SO_2$ 24-hour | 0.12 | CALPUFF | **0.2** | **100% Distillate Oil (0.05%S)** | **5** |
| $SO_2$ Annual | 0.003 | CALPUFF | **0.08** | **100% Distillate Oil (0.05%S)** | **2** |
| $PM_{10}$ 24-hour | 0.14 | CALPUFF | **0.32** | **100% Distillate Oil (0.05%S)** | **8** |
| $PM_{10}$ Annual | 0.003 | CALPUFF | **0.16** | **100% Distillate Oil (0.05%S)** | **4** |
| $NO_2$ Annual | 0.002 | CALPUFF | **0.1** | **100% Distillate Oil (0.05%S)** | **2.5** |

Note:
* 75**%** Distillate Oil (0.05%S) operating scenario maximum impacts were also above the Class I Significance Level.
**# = Proposed New Source Review Reform Class I significance levels**

## Table IV-14. CALPUFF Model Input Switches

| Parameter | Option(s) chosen |
|---|---|
| **INPUT GROUP 2 Technical options** | |
| **MGAUSS** Vertical distribution used in the near field. 1 = Gaussian | MGAUSS = 1 |
| **MCTADJ** Terrain adjustment method. 3 = partial plume path adjustment | MCTADJ = 3 |
| **MCTSG** Subgrid-scale complex terrain flag. 0 = not modeled | MCTSG = 0 |
| **MSLUG** Near-field puffs modeled as elongated. 0 = no | MSLUG = 0 |
| **MTRANS** Transitional plume rise modeled? 1 = yes (transitional rise computed) | MTRANS = 1 |
| **MTIP** Stack tip downwash? 1 = yes (use stack tip downwash) | MTIP = 1 |
| **MSHEAR** Vertical wind sheer modeled above stack top? 0 = no | MSHEAR = 0 |
| **MSPLIT** Puff splitting allowed? 0 = no, | MSPLIT = 0 |
| **MCHEM** Chemical mechanism flag. 3 = transformation rates computed internally (RIVAD/ARM3 scheme) | MCHEM = 3 |
| **MWET** Wet removal modeled? 1 = yes | MWET = 1 |
| **MDRY** Dry deposition modeled? 1 = yes (dry deposition method specified for each species in Input Group 3) | MDRY = 1 |
| **MDISP** Method used to compute dispersion coefficients. 3 = PG dispersion coefficients for RURAL areas (computed using the ISCST multi-segment approximation) and McElroy-Pooler (MP) coefficients in urban areas. | MDISP = 3 |
| **MTURBVW** $\sigma_v/\sigma_\theta$, $\sigma_w$ measurements used? (used only if MDISP = 1 or 5) | MTURBVW = 3 |
| **MDISP2** Back-up method used to compute dispersion when measured turbulence data are missing. **(**used only if MDISP = 1 or 5) | MDISP2 = 3 |
| **MROUGH** PG $\sigma_y$, $\sigma_z$ adjusted for roughness? 0 = no | MROUGH = 0 |
| **MPARTL** Partial plume penetration of elevated inversion? 1 = yes | MPARTL = 1 |
| **MTINV** Strength of temperature inversion provided in PROFILE.DAT extended records? 0 = no (computed from measured/default gradients) | MTINV = 0 |
| **MPDF** PDF used for dispersion under convective conditions? 0 = no | MPDF = 0 |
| **MREG** Test options specified to see if they conform to regulatory values? 0 = no checks are made. | MREG = 0 |
| **INPUT GROUP: 3a, 3b – Species list** **Subgroup (3a)** | |
| **CSPEC** The following species are modeled. | CSPEC = $SO_2$, $SO_4$, NO, $NO_2$, $HNO_3$, $NO_3$, $PM_{10}$ |

| Species Name | Modeled? 0=no, 1 = yes | Emitted? 0=no, 1 = yes | Dry Deposited? 0 = no, 1 = computed-gas, 2 = computed-particle | Output Group # 0=NONE |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| $SO_2$ | 1 | 1 | 1 | 0 |
| $SO_4$ | 1 | 0 | 2 | 0 |
| NO | 1 | 1 | 1 | 0 |
| $NO_2$ | 1 | 1 | 1 | 0 |
| $HNO_3$ | 1 | 0 | 1 | 0 |
| $NO_3$ | 1 | 0 | 2 | 0 |
| $PM_{10}$ | 1 | 1 | 2 | 0 |

**INPUT GROUP 7 – Chemical parameters for dry deposition of gases**

| **SPECIES NAME** | **DIFFUSIVITY** (cm**2/s) | **ALPHA STAR** | **REACTIVITY** | **MESOPHYLL RESISTANCE** (s/cm) | **HENRY'S LAW COEFFICIENT** (dimensionless) |
|---|---|---|---|---|---|
| $SO_2$ | 0.1509 | 1000 | 8. | 0. | 4.0E-02 |
| NO | 0.1345 | 1 | 2. | 25. | 18. |
| $NO_2$ | 0.1656 | 1 | 8. | 5. | 3.5E00 |
| $HNO_3$ | 0.1628 | 1 | 18. | 0. | 8.05E-08 |

**INPUT GROUP 8 – Size parameters for dry deposition of particles**

| **SPECIES NAME** | **GEOMETRIC MASS MEAN DIAMETER** (microns) | **GEOMETRIC STANDARD DEVIATION** (microns) |
|---|---|---|
| $SO_4$ | 0.48 | 2.0 |
| $NO_3$ | 0.48 | 2.0 |
| $PM_{10}$ | 0.48 | 2.0 |

**INPUT GROUP 9 – Miscellaneous dry deposition parameters**

| | |
|---|---|
| **RCUTR** Reference cuticle resistance. (s/cm) | RCUTR = 30. |
| **RGR** Reference ground resistance. (s/cm) | RGR = 5. |
| **REACTR** Reference pollutant reactivity. | REACTR = 8. |
| **NINT** Number of particle-size intervals used to evaluate effective particle deposition velocity. | NINT = 9 |
| **IVEG** Vegetation state in unirrigated areas. IVEG = 1 for active and unstressed vegetation. | IVEG = 1 |

**INPUT GROUP 10 – Wet deposition parameters**

| **POLLUTANT** | **SCAVENGING COEFFICIENT –** Units: (sec)**(-1) | |
|---|---|---|
| | **LIQUID PRECIPITATION** | **FROZEN PRECIPITATION** |
| $SO_2$ | 3.0E-05 | 0. |
| NO | 0. | 0. |
| $NO_2$ | 0. | 0. |
| $HNO_3$ | 6.0E-05 | 0. |
| $SO_4$ | 1.0E-04 | 3.0E-05 |
| $NO_3$ | 1.0E-04 | 3.0E-05 |
| $PM_{10}$ | 1.0E-04 | 3.0E-05 |

**INPUT GROUP 11 – Chemistry parameters**

| | |
|---|---|
| **BCKNH3** Background ammonia concentration in ppb. | BCKNH3 = 10. |
| **RNITE1** Nightime $SO_2$ loss rate in percent/hour. | RNITE1 = 0.2 |
| **RNITE2** Nighttime $NO_x$ loss rate in percent/hour. | RNITE2 = 2.0 |
| **RNITE3** Nightime $HNO_3$ formation rate in percent/hour | RNITE3 = 2.0 |

**INPUT GROUP 12 –Misc. Dispersion and Computational Parameters**

| | |
|---|---|
| **SYTDEP** Horizontal size of puff (m) beyond which time-dependent dispersion equations (Heffter) are used to determine sigma-y and sigma-z. | SYTDEP = 5.5E02 |
| **MHFTSZ** Switch for using Heffter equation for sigma-z as above. 0 = Not use Heffter. | MHFTSZ = 0 |
| **JSUP** Stability class used to determine plume growth rates for puffs above the boundary layer. | JSUP = 5 |

| | |
|---|---|
| **CONK1** Vertical dispersion constant for stable conditions (k1 in Eqn. 2.7.3). | CONK1 = 0.01 |
| **CONK2** Vertical dispersion constant for neutral/unstable conditions (k2 in Eqn. 2.7-4). | CONK2 = 0.1 |
| **TBD** Factor for determining Transition-point from Schulman-Scire to Huber-Snyder Building Downwash scheme (SS used for Hs < Hb + TBD * HL). TBD = 0.5 ==› ISC Transition-point. | TBD = 0.5 |
| **IURB1, IURB2** Range of land use categories for which urban dispersion is assumed | IURB1 = 10<br>IURB2 = 19 |
| **PUFF-SPLITTING CONTROL VARIABLES** | |
| **NSPLIT** Number of puffs that result every time a puff is split. | NSPLIT = 3 |
| **IRESPLIT(24)** Time(s) of a day when split puffs are eligible to be split once again. 0 = do not re-split, 1 = eligible for resplit | IRESPLIT(24) = 0.,0.,0.,0.,0.,0.,0.,0.,0., 0.,0.,0.,0.,0.,0.,0.,1.,0.,0.,0.,0.,0.,0.,0. |
| **ZISPLIT** Split is allowed only if last hour's mixing height (m) exceeds a minimum value. | ZISPLIT = 100 |
| **RDLDMAX** Split is allowed only if ratio of last hour's mixing ht to the maximum mixing ht experienced by the puff is less than a maximum value (this postpones a split until a nocturnal layer develops) | RDLDMAX = 0.25 |
| **INTEGRATION CONTROL VARIABLES** | |
| **EPSSLUG** Fractional convergence criterion for numerical slug sampling integration. | EPSSLUG = 1.0E-04 |
| **EPSAREA** Fractional convergence criterion for numerical AREA source integration | EPSAREA = 1.0E-06 |

H. Class I AQRV Analyses

The Federal Land Manager for the GGW and PRDRW Class I areas has identified scenic beauty, vegetation, wildlife, water and odor as AQRV's. The VISCREEN model was used to evaluate the scenic beauty (visibility) AQRV. Evaluation of all other AQRV's used USDA Forest Service recommended techniques outlined in the following document: *Screening Procedure to Evaluate Effects of Air Pollution on Eastern Region Wilderness Cited as Class I Air Quality Areas* (Adams et al, 1991, Gen. Tech. Rep. NE-151, Radnor, PA; US Dept. of Agriculture, Forest Service, Northeastern Forest Experiments Station)).

**CLASS I VISIBILITY:** A VISCREEN Level-1 analysis was used to assess visibility impacts on Class I areas inside GGW and PRDRW. There are no Integral Vistas identified for the GGW and PRDRW Class I areas, therefore only visibility impacts inside those Class I areas were analyzed. Table IV-15 summarizes the VISCREEN model input data for the Level-1 analysis. Data include source emission strengths for the facility, distances to the Class I areas, plume-observer angle, background visual range, model default values for meteorological conditions and background air quality levels.

**Table IV-15. VISCREEN Input Data**

| **POLLUTANT INPUT DATA** | |
|---|---|
| Pollutant | Maximum Operating Case Emissions (g/s) |
| Particulates | 22.932 |
| $NO_x$ (as $NO_2$) | 15.12 |
| Primary $NO_2$ | 0.00 |
| Soot | 0.00 |
| Primary $SO_4$ | 0.00 |

| **DEFAULT PARTICLE CHARACTERISTICS** | | | |
|---|---|---|---|
| Background Ozone | 0.10* ppm | | |
| Background Visual Range | 90.00** km | | |
| Plume-Source-Observer Angle | 11.25° | | |
| **DISTANCE INPUT DATA** | | | |
| | | **DISTANCE TO CLASS I AREAS** | |
| Class I Area | Source-Observer Distance (km) | Minimum Source-Class I Distance (km) | Maximum Source-Class I Distance (km) |
| GGW and PRDRW | 83.70 | 83.70 | 101.00 |

Notes:
*   = Minimum MEDEP-BAQ required ozone background is 0.04 ppm
** = Minimum MEDEP-BAQ required background visual range is 60 km

Results of the Level-1 analyses are summarized in Table IV-16. This table presents the worst-case plume perceptibility (Delta-E) and plume contrast values obtained for each situation analyzed. Level-1 screening results indicate that GELP's proposed facility will not cause plume visibility impacts within Class I areas. Because critical visibility values could be met using this method, no VISCREEN Level-2 or regional haze analyses were required.

**Table IV-16. VISCREEN Model Results in Class I Areas**

| **Level 1 Analysis** | | | | | | |
|---|---|---|---|---|---|---|
| | | | Inside Class I Area | | Integral Vistas | |
| | | | Delta E | Contrast (±) | Delta E | Contrast (±) |
| **CRITICAL VALUES** | | | 2.0 | 0.05 | 2.00 | 0.05 |
| **GGW AND PRDRW** | | | | | | |
| Case | Background | Sun Angle | Delta E | Contrast (±) | Delta E | Contrast (±) |
| 75% oil (2-units) | Sky | 10° | 1.964 | 0.030 | n/a | n/a |
| 75% oil (2-units) | Sky | 140° | 0.476 | -0.019 | n/a | n/a |
| 75% oil (2-units) | Terrain | 10° | 1.888 | 0.020 | n/a | n/a |
| 75% oil (2-units) | Terrain | 140° | 0.290 | 0.009 | n/a | n/a |

Note:
n/a = no integral vistas were identified for this Class I area.

**OTHER AQRV's:** Analysis of GELP's emissions on vegetation, wildlife, water and odor AQRV's in the GGW/PRDRW Class I areas was completed by the applicant's consultant using USDA Forest Service recommendations. Results of screening procedures show that total sulfur deposition exceeds the value used to define an adverse effect and more information is needed to document potential adverse effects from nitrogen deposition. In addition, recent ozone episodes have caused injury to sensitive trees, shrubs, and plants. No adverse impacts due to odor from GELP emissions will occur due to the clean technology and fuel (natural gas and 0.05%S distillate oil) that will be used. Since the projects impacts have been shown to be insignificant in the Class I area and the project will be required to obtain $NO_x$ offsets at a ratio of 1.15 to 1 and $SO_2$ allowances which will most likely originate from upwind areas, effects from acid deposition and ozone due to the projects emissions on AQRV's will not add to the already adverse impacts. Therefore, it is reasonably certain that GELP emissions will not significantly contribute to adverse impacts of any Class I AQRV.

I. Summary

It has been demonstrated that GELP's facility in its proposed configuration will not cause or contribute to a violation of any $SO_2$, $PM_{10}$, $NO_2$ or CO averaging period MAAQS or any $SO_2$, $PM_{10}$ or $NO_2$ Class II increment standards. It has also been demonstrated that GELP's facility in its proposed configuration, with the following restrictions:

- 0.05%S distillate oil may not be fired in more than two generation units simultaneously. When firing oil in two generation units simultaneously, neither unit shall be operated in excess of 75% of its design capacity.

- When firing 0.05%S distillate oil in only one generation unit, such unit may be fired at any load between 75% and 100 % of its design capacity.

will not cause or contribute to a violation of any $SO_2$, $PM_{10}$, or $NO_2$ averaging period Class I increment standards and will cause no impairment to AQRV's in Class I or II areas.

## ORDER

Based on the above Findings and subject to conditions listed below the Department concludes that the emissions from this source:

- will receive Best Practical Treatment,
- will not violate applicable emission standards,
- will not violate applicable ambient air quality standards in conjunction with emissions from other sources.

The Department hereby grants Air Emission License A-735-71-A-N subject to the following federally enforceable conditions:

**STANDARD CONDITIONS**

(1) Employees and authorized representatives of the Department shall be allowed access to the licensee's premises during business hours, or any time during which any emissions units are in operation, and at such other times as the Department deems necessary for the purpose of performing tests, collecting samples, conducting inspections, or examining and copying records relating to emissions.

(2) The licensee shall acquire a new or amended air emission license prior to commencing construction of a modification, unless specifically provided for in Chapter 115.

(3) Approval to construct shall become invalid if the source has not commenced construction within eighteen (18) months after receipt of such approval or if construction is discontinued for a period of eighteen (18) months or more. The Department may extend this time period upon a satisfactory showing that an extension is justified, but may condition such extension upon a review of either the control technology analysis or the ambient air quality standards analysis, or both.

(4) The licensee shall establish and maintain a continuing program of best management practices for suppression of fugitive particulate matter during any period of construction, reconstruction, or operation which may result in fugitive dust, and shall submit a description of the program to the Department upon request.

(5) The licensee shall pay the annual air emission license fee to the Department, calculated pursuant to Title 38 MRSA §353.

(6) The license does not convey any property rights of any sort, or any exclusive privilege.

(7) The licensee shall maintain and operate all emission units and air pollution control systems required by the air emission license in a manner consistent with good air pollution control practice for minimizing emissions.

(8) The licensee shall maintain sufficient records, to accurately document compliance with emission standards and license conditions and shall maintain such records for a minimum of six (6) years. The records shall be submitted to the Department upon written request.

(9) The licensee shall comply with all terms and conditions of the air emission license. The filing of an appeal by the licensee, the notification of planned changes or anticipated noncompliance by the licensee, or the filing of an application by the licensee for the renewal of a license or amendment shall not stay any condition of the license.

(10) The licensee may not use as a defense in an enforcement action that the disruption, cessation, or reduction of licensed operations would have been necessary in order to maintain compliance with the conditions of the air emission license.

(11) In accordance with the Department's air emission compliance test protocol and 40 CFR Part 60 or other method approved or required by the Department, the licensee shall:

A. perform stack testing to demonstrate compliance with the applicable emission standards under circumstances representative of the facility's normal process and operating conditions:

1. within sixty (60) calendar days of receipt of a notification to test from the Department or EPA, if visible emissions, equipment operating parameters, staff inspection, air monitoring or other cause indicate to the Department that equipment may be operating out of compliance with emission standards or license conditions; or

2. pursuant to any other requirement of this license to perform stack testing.

B. install or make provisions to install test ports that meet the criteria of 40 CFR Part 60, Appendix A, and test platforms, if necessary, and other accommodations necessary to allow emission testing; and

C. submit a written report to the Department within thirty (30) days from date of test completion.

(12) If the results of a stack test performed under circumstances representative of the facility's normal process and operating conditions indicate emissions in excess of the applicable standards, then:

A. within thirty (30) days following receipt of such test results, the licensee shall re-test the non-complying emission source under circumstances representative of the facility's normal process and operating conditions and in accordance with the Department's air emission compliance test protocol and 40 CFR Part 60 or other method approved or required by the Department; and

B. the days of violation shall be presumed to include the date of stack test and each and every day of operation thereafter until compliance is demonstrated under normal and representative process and operating conditions, except to the extent that the facility can prove to the satisfaction of the Department that there were intervening days during which no violation occurred or that the violation was not continuing in nature; and

C. the licensee may, upon the approval of the Department following the successful demonstration of compliance at alternative load conditions, operate under such alternative load conditions on an interim basis prior to a demonstration of compliance under normal and representative process and operating conditions.

(13) Notwithstanding any provision of this license or any other provision in the State Implementation Plan approved by the EPA or Section 114(a) of the CAA, any credible evidence may be used for the purpose of establishing whether a person has violated or is in violation of any statute, regulation, or Part 70 license requirement or PSD permit.

(14) The licensee shall maintain records of malfunctions, failures, downtime, and any other similar change in operation of air pollution control systems or the emissions unit itself that would affect emissions and that is not consistent with the terms and conditions of the air emission license. The licensee shall notify the Department within two (2) days or the next state working day, whichever is later, of such occasions where such changes result in an increase of emissions. The licensee shall report all excess emissions in the units of the applicable emission limitation.

(15) Upon the written request of the Department, the licensee shall establish and maintain such records, make such reports, install, use, and maintain such monitoring equipment, sample such emissions (in accordance with such methods, at such locations, at such intervals, and in such manner as the Department shall prescribe), and provide other information as the Department may reasonably require to determine the licensee's compliance status.

**SPECIFIC CONDITIONS**

(16) **Averaging Period Calculations**
The following shall apply to the conditions in this order as appropriate, unless it is stated otherwise for each unit:

A. A 24-hour block average basis shall be calculated as the arithmetic average of not more than 24 - one hour block periods. Only one 24-hour block average shall be calculated for one day, beginning at midnight. Hours in which no operation occurs shall not be included in the 24 hr block average calculation.

B. A 3-hour block average basis shall be calculated as the arithmetic average of not more than 3 - one hour block periods. No more than eight 3-hour block averages shall be calculated for one day. One 3-hour block average shall be calculated for the period from midnight to 3:00, one from 3:00 to 6:00, one from 6:00 to 9:00, etc.

C. A 30-day rolling average basis shall be calculated as the arithmetic average of not more than thirty 24-hour block averages as described in 40 CFR Part 60, Subpart Db.

(17) **Generation Systems #1, #2, and #3**

A. Each generation system shall consist of a combustion turbine followed by a heat recovery steam generator (HRSG) and a steam turbine; in addition to the following control equipment:
   1. Low $NO_x$ Combustors for $NO_x$ emission control;
   2. Selective Catalytic Reduction (SCR) for $NO_X$ emission control; and
   3. A catalyst for CO emission control.

B. Each generation system may fire either natural gas or distillate oil, not to exceed 0.05% sulfur by weight.

C. Each generation system shall exhaust into a stack that is at a minimum of 165 feet or at least 60% of good engineering practice stack height.

D. Each generation system shall operate at 75% capacity or higher when in operation, not including periods of startup and shutdown.

(18) **SCR Systems**

Ammonia shall not be injected into the SCR during start-up or shutdown unless the catalyst bed is at, or above, the manufacturer's specified minimum operating temperature.

(19) **Generation Systems #1, #2, and #3 - Capacity Limits**

A. Except during periods of steam injection, each generation system shall be limited to a fuel input capacity of 2002 MMBtu/hr when combusting natural gas.

B. Each generation system shall be limited to a fuel input capacity of 2194 MMBtu/hr when combusting natural gas during periods of steam injection.

C. Each generation system shall be limited to a fuel input capacity of 2230 MMBtu/hr when combusting oil.

(20) **Generation Systems #1, #2, and #3 - Emission Limits**

The emission limits given below shall apply at all times, except during periods of startup/shutdown, unavoidable malfunctions, on-load fuel switching, or initial commissioning as described in condition (27).

A. PM

PM emissions from each generation system shall not exceed the following:

| Pollutant | Operating Condition | Emission Rate |
|---|---|---|
| PM | natural gas firing | 27 lb/hr |
| | distillate oil firing | 112 lb/hr |

Compliance shall be demonstrated through stack testing in accordance with 40 CFR Part 60, Appendix A, Method 5.

B. $PM_{10}$

$PM_{10}$ emissions from each generation system shall not exceed the following:

| Pollutant | Operating Condition | Emission Rate |
|---|---|---|
| $PM_{10}$ | natural gas firing | 27 lb/hr |
| | distillate oil firing | 112 lb/hr |

Compliance shall be demonstrated through stack testing in accordance with 40 CFR Part 60, Appendix A, Method 201A.

C. $SO_2$

$SO_2$ emissions from each generation system shall not exceed the following:

| Pollutant | Operating Condition | Emission Rate | Averaging time |
|---|---|---|---|
| $SO_2$ | natural gas firing | Sulfur content of 0.8 grains/100 scf | ------- |
| | natural gas firing | 4.9 lb/hr | 24 hr block |
| | distillate oil firing | Sulfur content no greater than 0.05% | -------- |
| | distillate oil firing | 114 lb/hr | 24 hr block |

Compliance shall be demonstrated by fuel records.

D. $NO_X$

$NO_X$ emissions from each generation system shall not exceed the following:

| Pollutant | Operating Condition | Emission Rate | Averaging time |
|---|---|---|---|
| $NO_X$ | natural gas firing | 2.5 ppmv, dry, corrected to 15% $O_2$ | 3 hr block |
| | natural gas firing | 28 lb/hr | Stack tests |
| | steam injection | 3.5 ppmv, dry, corrected to 15% $O_2$ | 3 hr block |
| | steam injection | 28 lb/hr | Stack tests |
| | distillate oil firing | 9 ppmv, dry, corrected to 15% $O_2$ | 1 hr block |
| | distillate oil firing | 79 lb/hr | Stack tests |

Compliance for ppm shall be demonstrated by a CEMS. Compliance for lb/hr shall be based on stack tests in accordance with 40 CFR Part 60, Appendix A, method 20.

E. CO

CO emissions from each generation system shall not exceed the following:

| Pollutant | Operating Condition | Emission Rate | Averaging time |
|---|---|---|---|
| CO | Natural gas firing | 5 ppmv, dry, corrected to 15% $O_2$ | 24 hr block |
| | Natural gas firing | 24 lb/hr | Stack test |
| | Distillate oil firing | 10 ppmv, dry, corrected to 15% $O_2$ | 24 hr block |
| | Distillate oil firing | 53 lb/hr | Stack test |

Compliance with ppm shall be demonstrated by a CEMS. Compliance with lb/hr shall be based on stack tests in accordance with 40 CFR Part 60, Appendix A, method 10 using the gas filter correlation method.

F. VOC

VOC emissions from each generation system shall not exceed the following:

| Pollutant | Operating Condition | Emission Rate |
|---|---|---|
| VOC (as $CH_4$) | natural gas firing | 0.0017 lb/MMBtu |
| | natural gas firing | 3.8 lb/hr |
| | distillate oil firing | 0.0085 lb/MMBtu |
| | distillate oil firing | 19 lb/hr |
| | steam injection | 0.005 lb/MMBtu |
| | steam injection | 11 lb/hr |

Compliance shall be demonstrated through stack tests in accordance with 40 CFR Part 60, Appendix A, Method 18/25A.

G. Ammonia

Ammonia emissions from each generation system shall not exceed the following:

| Pollutant | Emission Rate | Averaging time |
|---|---|---|
| Ammonia | 20 ppmv, dry, corrected to 15% $O_2$ | 24 hr block |
| | 10 ppmv, dry, corrected to 15% $O_2$ | 30 day rolling |

Compliance with ppm shall be demonstrated by a CEMS.

Gorham Energy shall reevaluate the ammonia slip emissions within three years of the issuance of this license and submit the study to the Bureau of Air Quality.

H. Visible Emissions

1. Gorham Energy shall not exceed 20% opacity from each generation system stack, measured as 6 minute block averages, except for one 6 minute block average period per hour of not more than 27% opacity.

2. Compliance with the opacity limit shall be demonstrated during the initial performance test in accordance with 40 CFR Part 60, Appendix A, Method 9.

(21) **Allowable Oil Firing based on VOC Emissions**

A. The maximum hours of oil firing in the generation systems shall be based on the maximum VOC emissions allowed, calculated by the following equation:

$(1/2000) \times (0.0017\ Q_{gas} + 0.0085\ Q_{oil} + 0.005Q_{SI}) < 49$ tons/year

where: 1/2000 is the conversion factor from lb to tons
$Q_{gas}$ = total heat input (MMBtu) from gas firing (excluding steam injection)
$Q_{oil}$ = total heat input (MMBtu) from oil firing
$Q_{SI}$ = total heat input (MMBtu) from gas firing with steam injection
The equation is based on the VOC emissions rates in lb/MMBtu at all loads and ambient temperatures.

B. The total hours of oil firing may be divided in any portion between the three generation units.

C. Oil shall not be fired in more than two generation units simultaneously. When firing oil in two generation units, neither unit shall be operated in excess of 75% load.

D. When firing oil in only one generation unit, such unit may be fired at any load between 75% and 100%.

E. The capacity restrictions set forth in conditions (21)(C) and (D) above may be removed or changed pursuant to a minor revision to the air license upon submission by Gorham Energy of an air modeling quality analysis acceptable to the Department that demonstrates that the facility will not cause or contribute to a violation of ambient air quality standards or Class I increments at the alternate oil firing scenarios.

(22) **Fuel Testing**

A. Within 180 days after initial startup, Gorham Energy shall conduct tests on the natural gas being delivered to the facility. The testing shall include sulfur content, higher heating value, and representative metals as agreed to in the stack test protocol

B. Within 180 days after initial startup, Gorham Energy shall conduct tests on the distillate fuel oil being delivered to the facility. The testing shall include sulfur content, higher heating value, and representative metals as agreed to in the stack test protocol.

C. Gorham Energy shall conduct monthly testing of the quality of natural gas being delivered to the facility which shall include sulfur content and higher heating value. This is an alternate schedule for fuel testing in accordance with 40 CFR Part 60.334 (b)(2).

D. Gorham Energy shall monitor the quality of distillate oil delivered to the facility for sulfur and nitrogen content in accordance with 40 CFR Part 60.334 (b)(1) based on the test records provided by the fuel supplier.

(23) **Continuous Emission Monitors (CEM) and Parameter Monitors**

A. Each generation system shall operate the following CEMS:
1. $NO_X$
2. CO
3. Ammonia
4. Oxygen

B. Each CEM shall meet performance specifications, monitor location, calibration, and operating procedures and quality assurance procedures in accordance with the applicable requirements in 40 CFR Part 60.13, 40 CFR Part 60, Appendices B & F, 40 CFR Parts 72 and 75, and Chapter 117, Section 3 of the Department's regulations, as appropriate.

C. Gorham Energy shall submit a CEMS monitoring plan to the Bureau of Air Quality for review and approval at least 180 days prior to expected start-up.

D. All CEMS data shall be monitored and recorded continuously, as required by Chapter 117 of the Department regulations, 40 CFR Part 52.1020(c)(24), and 40 CFR Part 60.13, Appendices B and F, except for periods of calibration checks, zero and span adjustments and preventive maintenance or equipment malfunction. Each CEMS shall achieve the data recovery requirements of Chapter 117, Section 5 of the Department's regulations (ie. 90% data recovery as a percentage of source operating time per calendar quarter) and 40 CFR Part 52.1020(c)(24).

E. Gorham Energy shall monitor the parameters listed below:
   1. Natural gas flow to each combustion turbine shall be continuously monitored and recorded.
   2. A distillate fuel oil monitoring system shall be operated on each combustion turbine to record the total heat input from distillate oil.

   Each parameter monitor must record accurate and reliable data. If the parameter monitor is recording accurate and reliable data less than 98% of the source-operating time within any quarter of the calendar year, the Department may initiate enforcement action and may include in that enforcement action any period of time that the parameter monitor was not recording accurate and reliable data during that quarter unless the licensee can demonstrate to the satisfaction of the Department that the failure of the system to record accurate and reliable data was due to the performance of established quality assurance and quality control procedures or unavoidable malfunctions.

(24) **Recordkeeping**

Gorham Energy shall record the following for each generation system:

A. Hours of operation, including any startup, shutdown or malfunction in the operations of any component;

B. Routine maintenance or other repair or maintenance activities performed on the emission unit itself, its air pollution control system or the CEMS;

C. Any malfunction of the air pollution control system that causes any exceedance of any emission limitation;

D. Natural gas consumption per condition 23(E)(1);

E. The average daily input capacity in MMBtu/hr from natural gas;

F. The daily distillate oil consumption and the related heat input in MMBtu/hr;

G. The hours of steam injection and the related input capacity in MMBtu/hr;

H. The 12 month rolling total heat input provided by distillate oil firing.

I. The 12 month rolling total of VOC emissions calculated by the formula in condition (21).

(25) **Compliance Assurance**

The Bureau of Air Quality finds the following Compliance Assurance Plan to be reasonable and appropriate.

A. Quarterly Reporting
   1. The licensee shall submit a Quarterly Report to the Bureau of Air Quality within 30 days after the end of each calendar quarter, detailing the following, for the Control Equipment, Parameter Monitors, Continuous Emission Monitoring Systems (CEMS) required by this license:
      a. All control equipment downtimes and malfunctions which result in exceedances of emission limitations;
      b. All CEMS downtimes and malfunctions;
      c. All downtimes of the above specified parameter monitors;
      d. All excess events of emission and operational limitations set by this Order, statute, state or federal regulation, as appropriate; and
      e. A report certifying there were no excess emissions, if that is the case.

   2. The following information shall be reported for each excess event:
      a. Standard exceeded;
      b. Date, time, and duration of excess event;
      c. Maximum and average values of the excess event, reported in the units of the applicable standard, and copies of pertinent strip charts and print-outs when requested;
      d. A description of what caused the excess event;
      e. The strategy employed to minimize the excess event;
      f. The strategy employed to prevent reoccurrence; and

B. Record-Keeping
   1. For all of the equipment parameter monitoring and recording, required by this license, the licensee shall maintain records of the most current six year period and the records shall include:

a. Documentation which shows monitor operational status during all source operating time, including specifics for calibration and audits; and
b. A complete data set of all monitored parameters when parameter monitors are required to be operated as specified in this license. All parameter records shall be made available to the Bureau of Air Quality upon request.

2. The CEMS required by this license shall be the primary means of demonstrating compliance with emission standards set by this Order, statute, state or federal regulation, as applicable. For all CEMS, the licensee shall maintain records of the most current six year period and the records shall include:
   a. Documentation that all CEMS are continuously accurate, reliable and operated in accordance with Chapter 117 and 40 CFR Part 52.1020(c)(24); and
   b. Upon the written request by the Department, a report or other data indicative of compliance with the applicable emission standard for those periods when the CEMS were not in operation or produced invalid data. Evidence indicating normal operation shall constitute such reports or other data indicative of compliance with applicable standards. In the event the Bureau of Air Quality does not concur with the licensee's compliance determination, the licensee shall, upon the Bureau of Air Quality's request, provide additional data, and shall have the burden of demonstrating that the data is indicative of compliance with the applicable standard.

C. Stack Testing

1. The licensee shall conduct emission testing, and demonstrate compliance with the applicable standard within 60 days after receipt of notice from the Bureau of Air Quality.

2. The licensee shall conduct particulate emission testing and demonstrate compliance at least once every two years on a rotating basis for particulate matter for the following:

| **Pollutant** | **Operating Scenarios** | **# of Tests** | **EPA Method** |
|---|---|---|---|
| PM | 100% load | 1 | 5B |

Every two years, each system shall have a particulate test performed on a rotating basis based on fuel: one system firing oil, one system firing gas, and one system operating with steam injection. [example: 1st round of testing: System 1 oil, System 2 gas, System 3 steam injection. 2nd round of testing two years later: System 1 steam injection, System 2 oil, System 3 gas. 3rd round of testing in two more years: System 1 gas, System 2 steam injection, System 3 oil, etc.]

Gorham Energy may apply to amend the license to reduce the frequency of stack testing or to test only one generation system upon successful compliance demonstration of two consecutive stack tests (i.e. the first upon startup and the second two years after startup).

3. Performance Testing

Gorham Energy shall conduct the following initial performance tests within 60 days after achieving the maximum production rate at which the plant will be operated but not later than 180 days after the initial startup. All testing shall comply with all of the requirements of the DEP Compliance Test Protocol and with 40 CFR Part 60, as appropriate, or other methods or testing scenarios approved by the Bureau of Air Quality and EPA. A representative of the DEP or Environmental Protection Agency (EPA) shall be given the opportunity to observe the compliance testing.

i. $NO_X$ and VOC

| Unit | Gas Firing | Steam Injection | Oil Firing |
|---|---|---|---|
| 1 | 100%, 85%, 75% | 100% | 100%, 75% |
| 2 | 100%, 85%, 75% | 100% | 100%, 75% |
| 3 | 100%, 85%, 75% | 100% | 100%, 75% |

ii. $PM_{10}$

| Unit | Gas Firing | Steam Injection | Oil Firing |
|---|---|---|---|
| 1 | 100%, 75% | 100% | 100%, 75% |
| 2 | 100%, 75% | 100% | 100%, 75% |
| 3 | 100%, 75% | 100% | 100%, 75% |

4. All testing programs shall comply with all of the requirements of the DEP Compliance Test Protocol and with 40 CFR Part 60, as appropriate, or other methods approved by the Bureau of Air Quality and EPA.

(26) **New Source Performance Standard**

Gorham Energy shall comply with the requirements of the Federal New Source Performance Standards (NSPS) 40 CFR Part 60, Subparts A (General Provisions) and GG (Stationary Gas Turbines). Gorham Energy is not subject to Subparts D, Da, or Db.

(27) **Startup/Shutdown, Fuel Transfer, and Initial Commissioning**

A. The emission limits of condition (20) shall not apply during turbine startup/shutdown/equipment cleaning/fuel transfer conditions or each turbine's initial commissioning. Gorham Energy shall follow proper operating procedures during startup/shutdown/equipment cleaning/fuel transfer conditions and initial turbine commissioning to minimize the emission of air contaminants to the maximum extent reasonably practical.

B. Turbine startup/shutdown shall be defined as that period of time from initiation of combustion turbine firing until the unit reaches steady state load operation. Steady state operation shall be reached when the combustion turbine reaches minimum load (75%) and the steam turbine is declared available for load changes. This period shall not exceed 90 minutes for a hot start, 180 minutes for a warm start, nor 240 minutes for a cold start.

   The following definitions shall apply:

   1. Hot start shall be defined as startup when the generating unit has been down for less than or equal to 24 hours.

   2. Warm start shall be defined as startup when the generating unit has been down for more than 24 hours and less than or equal to 48 hours.

   3. Cold start shall be defined as startup when the generating unit has been down for more than 48 hours.

   4. Unit shutdown shall be defined as that period of time from steady state operation to cessation of combustion turbine firing. This period shall not exceed 60 minutes.

C. Fuel transfer shall be defined as that period of time from initiation of the fuel transfer sequence until the unit reaches steady state load operation on the new fuel. Steady state operation shall be reached when the combustion turbine reaches minimum load (75%) and the steam turbine is declared available for load changes. This period shall not exceed 60 minutes.

D. Initial turbine commissioning shall be defined as that period between initial startup of the first turbine to commercial acceptance of that power train, which period shall not exceed 180 days.

E. Within one year of initial startup, Gorham Energy shall propose to the Bureau of Air Qualtiy, numerical emission limits for CO, $NO_X$, and opacity to apply during startup and shutdown conditions. CEM data, stack test data gathered during startup/shutdown and/or other data acceptable to the Department shall be used as the basis for these limits.

(28) **Initial Startup Notification Requirements**

A. Gorham Energy shall notify the Bureau of Air Quality of the anticipated date of the initial start-up not more than 60 days nor less than 30 days prior to such date.

B. Gorham Energy shall notify the Bureau of Air Quality in writing of the date construction of the facility commenced no later than 30 days after such date.

C. Gorham Energy shall notify the Bureau of Air Quality in writing of the date of the actual initial start-up no later than fifteen days after such date.

D. Gorham Energy shall notify the Bureau of Air Quality in writing of the date upon which initial performance testing of the continuous emission monitors are scheduled to commence at least 30 days prior to such a date.

(29) **Offsets**
Prior to commencing operation, Gorham Energy shall demonstrate to the Bureau of Air Quality that $NO_X$ emission offset credits have occurred in the amount necessary to comply with Chapter 113 requirements. The emission offsets must be surplus, quantifiable, federally enforceable, and permanent.

(30) **Title V**
Within one year from the date of commencement of operation, the facility shall file an application for a Title V air emission license in accordance with Chapter 140 of the Department's regulations.

(31) **Acid Rain Program**

A. Gorham Energy shall apply for a license pursuant to 40 CFR Part 72, as a Phase II Acid Rain facility 24 months prior to startup or by January 1, 1999, whichever is later.

B. Gorham Energy shall obtain and hold in the EPA allowance Management System, sufficient Acid Rain allowances for each ton of $SO_2$ emitted annually in accordance with the requirements of 40 CFR Part 72.

(32) **Oil Storage Tank**
Pressure and vacuum relief valves on the oil storage tank shall be set at +/- 0.03 psig, respectively.

(33) **Emergency Diesel Fire Pump**
A. The emergency diesel fire pump shall use fuel with a sulfur content not to exceed 0.05% sulfur by weight. Fuel use records shall be kept documenting the sulfur content.

B. The emergency diesel fire pump shall be limited to 500 hours per year, based on a 12 month rolling total. An hour meter shall be installed and operated on the emergency diesel fire pump.

C. Emissions from the emergency diesel fire pump shall not exceed the following:

| Pollutant | lb/hr | tons/yr |
|---|---|---|
| PM | 0.47 | 0.12 |
| $PM_{10}$ | 0.47 | 0.12 |
| $SO_2$ | 0.11 | 0.03 |
| $NO_X$ | 6.62 | 1.7 |
| CO | 1.43 | 0.36 |
| VOC | 0.54 | 0.14 |

D. Visible emissions from the emergency diesel fire pump shall not exceed 30% opacity on a six minute block average basis, for more than two 6-minute block averages in a 3-hour period.

(34) **Emergency Diesel Generators**

A. The emergency diesel generators shall use fuel with a sulfur content not to exceed 0.05% sulfur by weight. Fuel use records shall be kept documenting the sulfur content.

B. The emergency diesel generators shall each be limited to 500 hours per year, based on a 12 month rolling total. An hour meter shall be installed and operated on each emergency diesel generator.

C. Emissions from each of the emergency diesel generators shall not exceed the following:

| Pollutant | lb/hr | Tons/yr |
|---|---|---|
| PM | 1.33 | 0.33 |
| $PM_{10}$ | 1.33 | 0.33 |
| $SO_2$ | 0.17 | 0.05 |
| $NO_X$ | 9.4 | 2.35 |
| CO | 4.6 | 1.15 |
| VOC | 0.54 | 0.14 |

D. The emergency generators shall not be operated unless one or more combustion turbines are shut down or are being shut down.

E. Visible emissions from each of the emergency diesel generators shall not exceed 30% opacity on a six minute block average basis, for more than two 6-minute block averages in a 3-hour period.

(35) **Facility Emissions**
Facility emissions shall be limited to the following, based on a 12 month rolling total:

| Pollutant | tons/year |
|---|---|
| PM | 328 |
| $PM_{10}$ | 328 |
| $SO_2$ | 98 |
| $NO_X$ | 248.63 |
| CO | 283 |
| VOC | 49.8 |
| Ammonia | 346 |

(36) The term of this license shall be five years from the signature date below.

DONE AND DATED IN AUGUSTA, MAINE THIS DAY OF 1998.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

BY: ______________________________________________
EDWARD O. SULLIVAN, COMMISSIONER

PLEASE NOTE THE ATTACHED SHEET FOR GUIDANCE ON APPEAL PROCEDURES

Date of initial receipt of application April 21, 1998
Date of application acceptance April 23, 1998

Date filed with the Board of Environmental Protection ______________________

This Order prepared by Kathleen E. Neil, Bureau of Air Quality.